VICTORIAN GAS OPERATIONS PLAN – WINTER 2017

GAS REAL TIME OPERATIONS

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AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

AEMO has prepared this document to provide information about the operation of the Victorian gas transmission system and the market operational strategies for winter 2017. The strategies are designed to support the secure operation of the Victorian Declared Transmission System (DTS) and the Declared Wholesale Gas Market (DWGM).

The annual winter stakeholder information session was held on 10 May 2017 to present the winter 2017 plan to stakeholders for discussion and comment.

This document supplements the session, and provides further technical information on the winter 2017 plan.

Disclaimer

This document is not exhaustive and cannot cover every possible situation. It contains information based on methodologies and assumptions that may not be applicable to every situation. This document represents general principles applicable to most situations, subject at all times to exceptions. This document should be considered along with the various applicable industry rules and procedures. The language and terminology is consistent with the 2017 Victorian Gas Planning Report. Where a contingency or event is of such severity that it cannot be managed using the principles described in this document, other strategies, guidelines or procedures may be used.

Version control

Version	Release date	Changes
1	10/5/2017	Incorporate updates for high risk issues identified for the Winter 2017 period.

EXECUTIVE SUMMARY

AEMO is the operator of the Victorian Gas Declared Transmission System (DTS) and the Declared Wholesale Gas Market (DWGM). As operator, AEMO is responsible for operating the Victorian gas transmission system in a safe, secure manner and for minimising threats to system security. This document, reviewed and published annually, details AEMO's operational and market strategies for operating the DTS and DWGM during the peak demand period in winter 2017.

The key messages for the winter strategy are outlined below.

Key messages

- Victorian peak day supply capacity is expected to be sufficient to meet a forecast 1-in-20 peak system demand day, and to support forecast DTS-connected Gas Powered Generation (GPG) demand.
- GPG consumption is forecast to increase in 2017 with an increased likelihood of GPG occurring on a peak winter demand day. This forecast is primarily driven by the March 2017 closure of the coal-fired Hazelwood Power Station.
  - Modelling conducted for the 2017 Victorian Gas Planning Report[1] (2017 VGPR) shows that if the GPG load is accurately forecasted at the start of the gas day, the DTS can support this demand up to the DTS peak day system capacity.
  - The ability of the DTS to support GPG is reduced if the load is unforecast, as there is insufficient usable linepack within the DTS. Depending on the location and magnitude of the unforecast GPG load, it is possible that additional non-firm LNG would be required or there would be a requirement for gas load curtailment.
- The reliance on storage at both the Iona Underground Gas Storage (Iona UGS) and Dandenong LNG facilities is critical to meet peak day demand for the entire winter period. AEMO will monitor storage inventory throughout winter to identify any supply concerns.
  - If storage drops to a low level early in winter, AEMO will communicate with industry and the Victorian Government to examine alternate supply options or mandatory restrictions.
  - A diverse source of supplies is required to ensure sufficient gas supply to meet demand for the entire winter period from 1 May to 30 September.
  - If storage is emptied prior to the end of winter and a peak system demand day then occurred, a gas supply shortfall would occur resulting in the curtailment of gas customers.
- AEMO actively manages the DTS limited linepack to support surprise demand (including unforecast GPG) or unexpected weather events. On a peak system demand day in winter, the usable linepack is turned over up to three times during a single gas day.
- AEMO expects that current transmission and market operational strategies will be sufficient to manage any potential threats to system security despite the increased operational challenges that have been identified.

Gas Supply Adequacy

AEMO does not expect a supply shortfall for the 2017 winter period. As indicated in the *2017 VGPR*, the supply tightness is not expected to eventuate until winter 2018.

[1] AEMO, 2017 Victorian Gas Planning Report. Available at: https://www.aemo.com.au/Gas/National-planning-and-forecasting/Victorian-Gas-Planning-Report

Winter 2017 DTS gas demand is forecast at:

- 1,198 terajoules (TJ) for a 1-in-2 system demand day.
- 1,310 TJ for a 1-in-20 system demand day.

The winter 2017 gas system consumption forecast has increased slightly compared to winter 2016 forecast. The major change in demand is anticipated to be associated with GPG requirements.

The 2016 peak demand day for the DTS occurred on Friday 24 June 2016. The total demand[2] of 1,187 TJ was all system demand, with no GPG being required on that day.

Actual peak day system demands have not decreased, as residential winter demand growth has offset industrial closures. The average peak winter demand over the last six years, shown in Table 1, is 1,165 TJ, which is relatively close to the 1-in-2 system demand day.

Table 1 Annual and winter gas consumption, and peak gas total demand

	2011	2012	2013	2014	2015	2016	2017*
Annual system consumption (petajoules (PJ))	217	211	200	195	208	204	196
Annual GPG consumption (PJ)	8	3	3	4	3	4	19
1 May - 30 September total consumption (PJ)	123	125	115	115	128	120	127
Actual peak total demand (TJ/d)	1,154	1,092	1,165	1,214	1,179	1,187	N/A

* Forecast per the 2017 VGPR

The total available daily gas supply to the Victorian DTS is estimated at 1,816 TJ/d. The total supply consists of the Gippsland (1,169 TJ/d) and Port Campbell (647 TJ/d) regions. Additional supplies are available from:

- The Dandenong liquefied natural gas (LNG) facility (87 TJ/d);
- Imports from the Victorian Northern Interconnect (VNI) (125 TJ/d); and
- Injections from the TasHub injection point (120 TJ/d).

Victorian gas supply is 593 TJ/d more than the forecast 1-in-20 peak system demand day of 1,310 TJ/d for winter 2017. Due to pipeline capacity constraints detailed in the next section, the full supply capacity could not be utilised for Victoria and this excess supply is used to support New South Wales, South Australia and Tasmanian gas demand.

DTS transportation capacity

System capacity is defined as the total quantity of gas that can be injected into the DTS on a gas day. The system capacity is limited by the following pipelines transportation capacities towards Melbourne;

- The Longford to Melbourne Pipeline (LMP) with a capacity of 1,030 TJ/d
- The South West Pipeline (SWP) with a capacity of 413 TJ/d

There are further limitations when both pipelines are near their maximum flow capacity, because the LMP and SWP cannot operate at their maximum capacity simultaneously as the pipelines back each other out of the DTS due to its limited linepack.

The peak day scenario used to determine system capacity assumes no Culcairn import or export flows, and no GPG demand. The maximum system capacity:

- Without LNG is 1,380 TJ/d
- With LNG is 1,500 TJ/d

2 Total demand is equal to the sum of system demand and GPG, but excludes exports.

On peak system demand days, the DTS has limited spare pipeline capacity of only 70 TJ/d to meet the peak 1-in-20 system demand day of 1,310 TJ/d without injections of operational response LNG being required. The peak day supply and demand scenario shows that, without LNG being scheduled, there is a limited ability to support any GPG or Culcairn exports.

Peak demand management

A normal operating state, as defined in the Wholesale Market System Security Procedures (Victoria), is where system pressures and flows are maintained within the defined operating limits.

The strategies highlighted in this document are expected to enable AEMO to meet these system security requirements and minimise threats to system security on peak days.

On a peak demand day these strategies include:

- Longford injection profiling to maximise usable linepack before the evening peak.
- Using the demand override methodology if substantial demand forecasting differences are identified.
- Should a threat to system security occur:
  - AEMO assesses and notifies the market of the threat.
  - If there is sufficient time, AEMO may request the market to respond to alleviate the threat.
  - If there is insufficient time, or the market response is inadequate to alleviate the threat, AEMO will take action in the priority order outlined in the Wholesale Market System Security Procedures (Victoria). This includes injecting LNG at the Dandenong facility.

AEMO will regularly communicate relevant information to participants.

If an emergency occurs, AEMO utilises the Emergency Procedures Gas.[3] The Emergency Procedures Gas are designed to enhance AEMO's and industry's ability to manage the preparation for, response to and recovery from gas emergencies in Victoria. AEMO also has an Emergency Management Framework and Incident Management Plan to ensure the safety, security and reliability of the DTS.

Supportability of Gas Powered Generation

The closure of the coal-fired Hazelwood Power Station is expected to drive GPG demand to increase from 4 PJ in 2016 to 19 PJ in 2017. This increase will occur mainly in the summer months and on peak winter demand days. Modelling conducted for the *2017 VGPR* demonstrated that the National Electricity Market (NEM) requires up to 110 TJ/d of GPG demand for a peak winters day.

AEMO has strategies for managing surprise demand from deteriorating weather conditions and unforecast GPG during peak demand periods. If GPG demand is accurately forecast in the DWGM, GPG is expected to be supportable under all normal operating conditions.

The DTS has limited capacity to support GPG demand during winter, because:

- Instantaneous GPG hourly demand can be high, and can reduce linepack levels quickly.
- The DTS has very limited usable linepack during winter.

To help manage uncertainties around GPG operation, AEMO:

- Monitors forecast GPG in both the DWGM and NEM pre-dispatch.
- Communicates with the AEMO NEM control rooms in Sydney and Brisbane, and support teams, regarding NEM reserve levels, and generator outages.
- Communicates with market participants to obtain information on possible GPG operations.

[3] AEMO, *Emergency Procedures (Gas)*. available at: http://www.aemo.com.au/Gas/Emergency-management/Victorian-role

Modelling shows that if 110 TJ/d of GPG load is forecast at the start of the gas day on a 1-in-2 system demand day:

- No operational response LNG would be required if there were no Culcairn exports.
- 50 TJ of firm operational response LNG would be required to support the GPG if there is 150 TJ of coincident Culcairn exports.

The ability of the DTS to support GPG is reduced if the load is unforecast, because there is insufficient usable linepack. Unforecast GPG may result in a threat to system security that would require AEMO to respond with one, or more, of the following mechanisms:

- Operational response LNG;
- Ad hoc schedules;
- Directions to participants or facility operators; or
- Gas load curtailments.

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CHAPTER 1. WINTER 2017 OUTLOOK

Victorian peak day supply capacity is expected to be sufficient to meet a forecast 1-in-20 peak system demand day, and support forecast DTS-connected GPG demand.

- Winter 2017 1-in-20 peak system demand is forecast to be 1,310 TJ/d.
- The maximum peak day supply is 1,380 TJ/d.
- On peak days the DTS has limited spare pipeline capacity of only 70 TJ/d to meet the peak system demand of 1,310 TJ/d. The peak day supply and demand scenario shows that without LNG being available, there is a limited ability to support any GPG or Culcairn exports.

1.1 Supply and Demand Adequacy

The winter 2017 gas consumption and peak demand in the Declared Transmission System (DTS) is expected to be similar to 2016 with the exception of increased GPG demand.

This paper uses the annual gas system consumption forecasts in AEMO's *2016 National Gas Forecasting Report* (2016 NGFR).[4] GPG consumption forecasts published in the Winter Plan use the GPG forecast from the 2017 VGPR.

The Wholesale Market System Security Procedure[5] defines winter as the period from 1 May to 30 September.

1.1.1 Winter Peak System Demand

Actual peak system demand in 2016 was 1,187 TJ. The winter 2017 peak system demand for the DTS is forecast to be:

- 1,198 TJ for a 1-in-2 system demand day.
- 1,310 TJ for a 1-in-20 system demand day.

Monthly Gas Consumption

Table 2 shows the DTS average monthly winter consumption forecast for 2017 by DTS system withdrawal zone. Peak demand is expected to occur between 1 June and 31 August.

Table 2 2017 DTS average monthly winter consumption forecast (PJ)

	May	Jun	Jul	Aug	Sep	Total
Ballarat	1.17	1.37	1.51	1.38	0.95	6.38
Geelong	2.34	2.55	2.82	2.62	1.70	12.03
Gippsland	1.41	1.52	1.67	1.63	1.31	7.54
Melbourne	14.4	17.0	19.0	17.0	11.9	79.3
Northern	2.15	2.54	2.67	2.43	1.84	11.63
Western	0.41	0.43	0.48	0.45	0.41	2.18
System consumption	21.9	25.4	28.2	25.5	18.1	119.06

4 AEMO. *2016 National Gas Forecasting Report*. Available at: https://www.aemo.com.au/Gas/National-planning-and-forecasting/National-Gas-Forecasting-Report

5 AEMO, *Wholesale Market System Security Procedures Victoria*. Available at: http://www.aemo.com.au/Gas/Declared-Wholesale-Gas-Market-DWGM/Policies-and-procedures

The forecast shows that:

- July 2017 is expected to be the highest gas consumption month.
- 67% of winter withdrawals are expected to be from the Melbourne system withdrawal zone, 10% from the Geelong system withdrawal zone, and 10% from the Northern system withdrawal zone.
- Total winter 2017 forecast consumption is expected to be 119.1 petajoules (PJ), which is 61% of the 2017 calendar year forecast consumption of 196 PJ.

1.1.2 Gas supply

The DTS total daily maximum gas supply for 2017 is expected to be 1,380 TJ, which is sufficient to meet a 1-in-20 system demand day of 1,310 TJ/d. Table 3 summarises supply sources, their available maximum supply to inject into the DTS on a peak demand day, and their forecast production range for 2017.

This report uses gas supply, production and capacity information from AEMO's 2017 VGPR.

Table 3 2017 DTS supply sources and maximum daily supply (TJ)

DTS Supply Sources	Peak demand day	Total plant production capacity[6]
Gippsland	947	1,169
Port Campbell	433[7]	647
Total	1,380	-
Other supply sources	**Maximum Supply**	
LNG	87	
VNI Import	125	

The total daily maximum gas supply of 1,380 TJ comprises supply from Longford and VicHub, BassGas and Port Campbell production facilities (see following sections). Neither LNG nor Victorian Northern Interconnect (VNI) imports are part of the total daily maximum gas supply, because:

- LNG has historically been used to maintain system security and there is limited storage inventory.
- VNI import availability depends on operational and market conditions in New South Wales, which has been observed to limit flows on peak days.

Longford, VicHub and TasHub

Longford, VicHub, TasHub (connecting the Tasmanian Gas Pipeline (TGP) to the DTS) and BassGas maximum daily supply availability to the DTS is expected to be 947 TJ.

During winter 2017 gas is expected to continue to flow from Longford to New South Wales via the Eastern Gas Pipeline (EGP) and to Tasmania via the TGP. The demands from New South Wales and Tasmania, supplied from Longford, are not projected to have a material impact on gas supply to the DTS in winter 2017.

Interconnected energy markets' gas demands are discussed further in Section 2.4.

Port Campbell

The Port Campbell supply region provides gas up to the daily injection capacity of 433 TJ into the DTS. This is made up of Iona UGS, which also processes gas from the offshore Casino development, and the Otway and Minerva gas plants. The Port Campbell region's total plant production capacity is split between the DTS, Mortlake GPG, and South Australia via the SEA Gas Pipeline.

[6] Nameplate capacity expected based on information provided to AEMO's *2017 Victorian Gas Planning Report*.

[7] The transportation capacity of the South West Pipeline is 413 TJ/d, however an additional 20 TJ/d can be injected at Iona to support demand within the Western Transmission System.

LNG

LNG can be injected in the DTS for two main purposes:

- Operational response (otherwise known as peak shaving gas), where AEMO schedules out of merit order gas in response to a threat to system security.
- Market response, where market participants can use LNG, as they would any other injection facility, to manage their gas supply portfolio.

When used, LNG can be injected at either a:

- Firm rate of up to 5.5 TJ per hour TJ/hr; or
- Non-firm rate of up to 9.9 TJ/hr.

When used for operational response, LNG is not usually scheduled from the beginning-of-day, but is included in an intraday schedule for linepack management purposes. LNG only effectively supports system pressures when injected before 10:00 pm, which is when DTS linepack is at its lowest point.

A total of 129 TJ (2,356 tonnes) of LNG was scheduled by the market into the DTS during winter 2016. Operational response LNG was only used to avert a Threat to System Security on 1 October 2016.

VNI import

The VNI is connected to the Moomba to Sydney Pipeline (MSP) and can import and export gas between Victoria and New South Wales. VNI flow direction can depend heavily on market conditions in the DWGM, the STTM Sydney Hub and Shipper/Retailer portfolio balancing in the NEM.

The VNI maximum import capacity is highly dependent on New South Wales' transmission system conditions. These conditions may include New South Wales GPG demand, MSP linepack levels, and regional demand in southern New South Wales. The highest daily VNI import quantity during winter 2016 was 36 TJ.

1.1.3 Peak Day Supply and Demand

On peak demand days the DTS is expected to rely on injections at Longford (including VicHub and TasHub). Typically, 69% of the peak day supply is delivered from the Longford injection points.

AEMO expects Port Campbell supply into the DTS to be maximised on peak demand days.

LNG injection is available to provide additional gas supply, should the DTS experience any pipeline congestion, supply outages, or very high unforecast demand.

AEMO has considered three scenarios to demonstrate a potential supply and demand balance within the DTS for a 1-in-20 system demand day:

- Scenario 1 – base scenario.
- Scenario 2 – reduced Longford injection.
- Scenario 3 – reduced Longford injection with GPG.

The scenarios do not take into account any pipeline dynamics. DTS peak demand can be satisfied in all scenarios, by scheduling gas from sources such as LNG and VNI imports under a variety of supply conditions. This assumes an accurate beginning-of-day demand forecast, no facility deviations, and perfect linepack distribution. The supply-demand balance does not account for intraday DTS congestion.

Scenario 1 – base scenario

Base scenario considers that all peak day supplies are available on a 1-in-20 system demand day, as shown in Table 4. Under this scenario, the DTS has enough supply to meet the 1-in-20 system demand day.

Table 4 Scenario 1 peak day supply and demand

Supply		Demand	
Source	**TJ**	**Source**	**TJ**
Longford, VicHub and TasHub	887	1-in-20 system demand	1,310
BassGas	60	GPG	0
Port Campbell	433	VNI export	0
Total supply	**1,380**	**Total demand**	**1,310**

Scenario 2 – reduced Longford injection

Scenario 2 considers Longford supply into the DTS being reduced by 100 TJ on a 1-in-20 system demand day, assuming Longford supplies this gas to other markets. The scenario assumes other supply sources are fully available.

As Table 5 shows, this scenario projects a DTS shortfall of 30 TJ resulting in LNG or VNI imports being scheduled as alternate supply sources.

Table 5 Scenario 2 peak day supply and demand

Supply		Demand	
Source	**TJ**	**Source**	**TJ**
Longford, VicHub and TasHub	787	1-in-20 system demand	1,310
BassGas	60	GPG	0
Port Campbell	433	VNI export	0
Total supply	**1,280**	**Total demand**	**1,310**

Scenario 3 – reduced Longford injection with GPG

Scenario 3 builds on scenario 2, considering Longford injection being reduced by 100 TJ and GPG demand being 110 TJ/d (as per the 2017 VGPR DTS connected GPG forecast), on a 1-in-20 system demand day.

As Table 6 shows, this scenario projects a DTS shortfall of 140 TJ. This is greater than the maximum firm rate of LNG injections of 87 TJ/d, meaning that non-firm rate LNG injections, increased supply from the Longford injection points or VNI imports would be required to prevent this shortfall.

Table 6 Scenario 3 peak day supply and demand

Supply		Demand	
Source	**TJ**	**Source**	**TJ**
Longford and VicHub	787	1-in-20 system demand	1,310
BassGas	60	GPG	110
Port Campbell	433	VNI export	0
Total supply	**1,280**	**Total demand**	**1,420**

1.2 Pipeline Capacity

There are three major pipelines in the DTS, which make up the total system capacity:

- Longford to Melbourne Pipeline (LMP)
- South West Pipeline (SWP)
- Victoria Northern Interconnect (VNI)

When gas flows along a pipeline, there is a physical limit to the quantity that can flow. The pressure drop along the pipeline increases as flowrate increases, and the maximum possible flowrate along any given section of a pipeline is limited by the maximum and minimum allowable pressures.

1.2.1 DTS maximum injection capacity

Table 7 shows the maximum injection capacities within the DTS. AEMO schedules injections and withdrawals in the DTS considering these physical capacities, taking forecast demand into account.

Table 7 DTS maximum pipeline capacities, 2017

Major pipelines	Injection point	Pipeline capacity (TJ)
LMP	Longford, VicHub, TasHub, BassGas	1,030[8]
SWP	Port Campbell	433[9]
VNI	Culcairn	125[10]

For injection points, the amount of gas that can be injected into the pipeline increases with system demand, as gas is consumed and withdrawn along the pipeline. The opposite is true for controllable withdrawals, since gas flowing towards the withdrawal point is consumed, reducing the quantity available for withdrawal.

1.2.2 Longford to Melbourne Pipeline

The LMP daily injection capacity is 990 TJ/d if only Longford (including Vic Hub and TasHub) is injecting.

The combined maximum injection capacity from Longford and BassGas is 1,030 TJ/d.

1.2.3 South West Pipeline

The Winchelsea compressor allows up to 413 TJ/d to be injected from Port Campbell to Melbourne. This does not include the additional 20 TJ/d of demand that is supported in the Western Transmission System.

Figure 1 shows the import capacity for the SWP for varying system demand, with and without the Winchelsea compressor.

The maximum import capacity, with Winchelsea available has reduced from 446 TJ/d in 2016 to 433 TJ/d in 2017 due to decline in demand in the Geelong system withdrawal zone on a 1-in-20 peak day.

[8] The Longford maximum injection capacity is 990 TJ if BassGas is not injecting, otherwise the combined maximum capacity for injection of Longford, VicHub and BassGas is 1,030 TJ (with 970 TJ from Longford / VicHub / TasHub combined and 60 TJ from Bass Gas).

[9] 413 TJ/d pipeline capacity plus 20 TJ/d to supply Western Transmission System on a 1-in-20 peak day.

[10] Current VNI injection capacity is 196 TJ/d. Once VNIE Phase B is completed export capacity will be 223TJ/d, but assets outside the DTS, in New South Wales limit injections to 125 TJ/d.

Figure 1 South West Pipeline to Melbourne, 2017

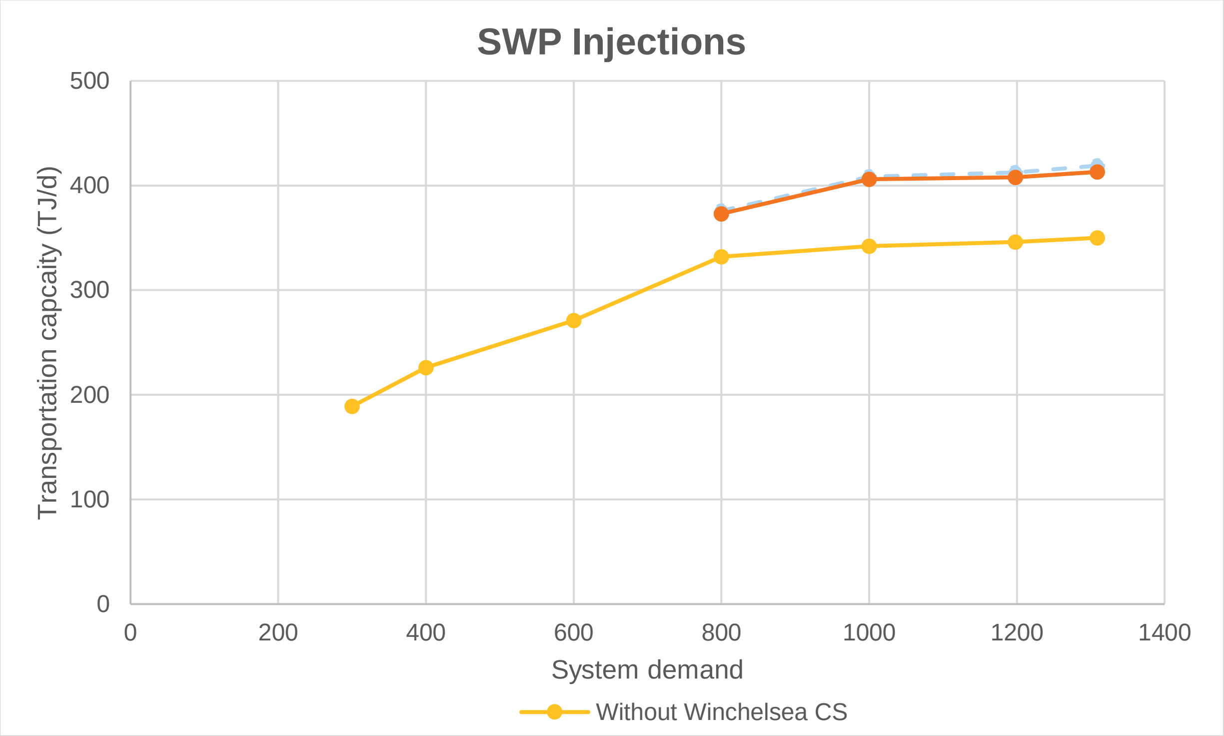
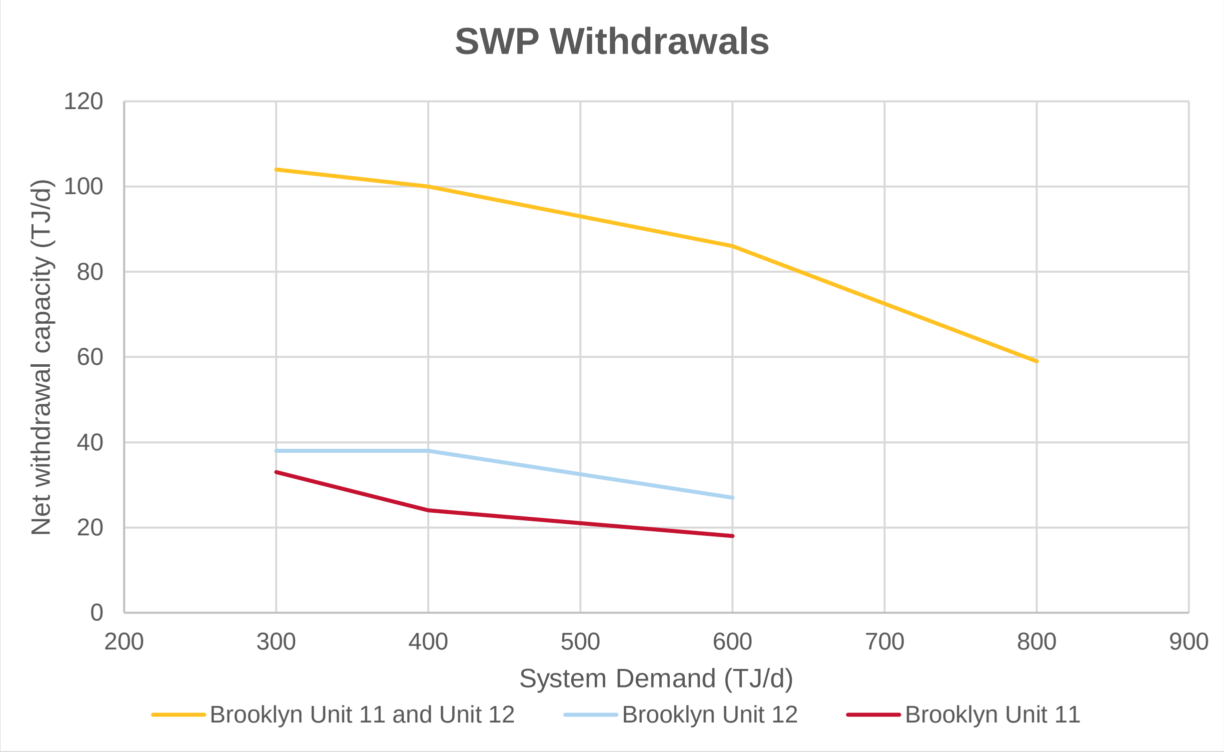


Figure 2 shows the export capacity for the SWP for varying system demand, with one or both Brooklyn units available. The maximum SWP export capacity in 2017, with both Brooklyn units 11 and 12 available is 104 TJ/d; this is slightly higher than 2016.

Changes have been made to the export capacities for different demand ranges. For lower demand ranges of 300 to 400 TJ/d, the capacity has increased slightly due to lower demand on the SWP and WTS. However, for demand ranges above 600 TJ, there has been a decrease in export capacity due to a revision of individual Brooklyn CS unit powers. Exports are not expected for demand above 800 TJ.

Figure 2 Melbourne to South West Pipeline, 2017



The SWP export capacity reduces significantly when only one Brooklyn Centaur compressor is available. For a 600 TJ day, the export capacity reduces from 86 to 27 TJ/d if unit 11 becomes unavailable.

1.2.4 Victoria Northern Interconnect

VNI expansion project

System augmentations are currently being completed to increase the VNI export and import capacities. At project completion, planned for winter 2017, the:

- VNI import capacity will increase from 197 TJ/d to 223 TJ/d, however pipeline assets outside the DTS in New South Wales will limit injections to the existing 125 TJ/d.
- VNI export capacity will increase from 148 TJ/d to 223 TJ/d. The facility operator for the New South Wales transmission system north of Culcairn has advised that exports of above 200 TJ/d may not be achieved, due to pressure requirements upstream of Culcairn.

The augmentations include pipeline duplications and modifications to regulating equipment at Euroa and Wollert, as well as reconfiguration of the Springhurst compressor, to allow higher flowrates to support the increased pipeline capacity.

VNI capacity

Figure 3 shows the VNI export capacity over the expected system demand ranges in 2017 for a variety of compressor combinations prior to VNIE Phase B project completion.

When all three compressors (Wollert, Euroa and Springhurst) are available, the VNI export capacity does not vary significantly with demand, and daily capacity is expected to be in the range 148 to 153 TJ. When only two compressors are available, the export capacity becomes much more demand dependent.

Figure 3 VNI export capacity for winter 2017 – Pre VNIE Phase B completion

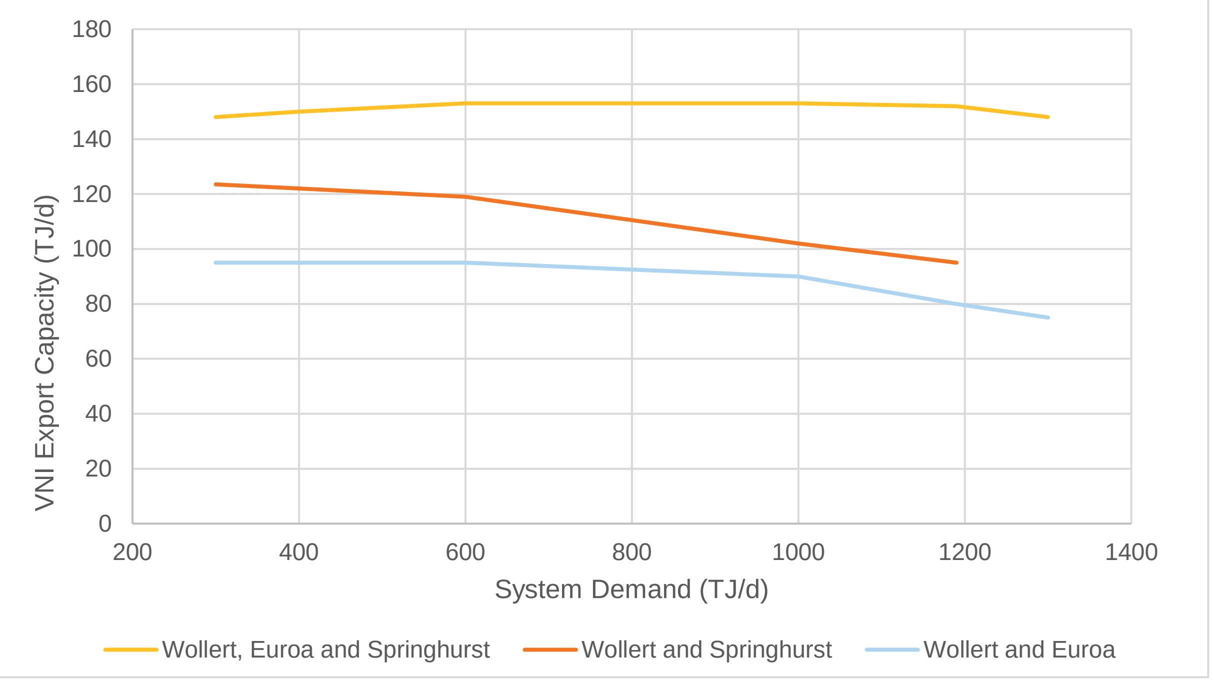


Figure 4 shows the VNI export capacity over the expected system demand ranges in 2017 for a variety of compressor combinations after the VNIE Phase B project completion, which is the full duplication of the VNI.

When all three compressors (Wollert, Euroa and Springhurst) are available, the VNI export capacity does not vary significantly with demand, and daily capacity is expected to be in the range 200 to 223 TJ/d. When only two compressors are available, the export capacity becomes much more demand-\ dependent.

Figure 4 VNI export capacity for winter 2017 – Post VNIE Phase B completion

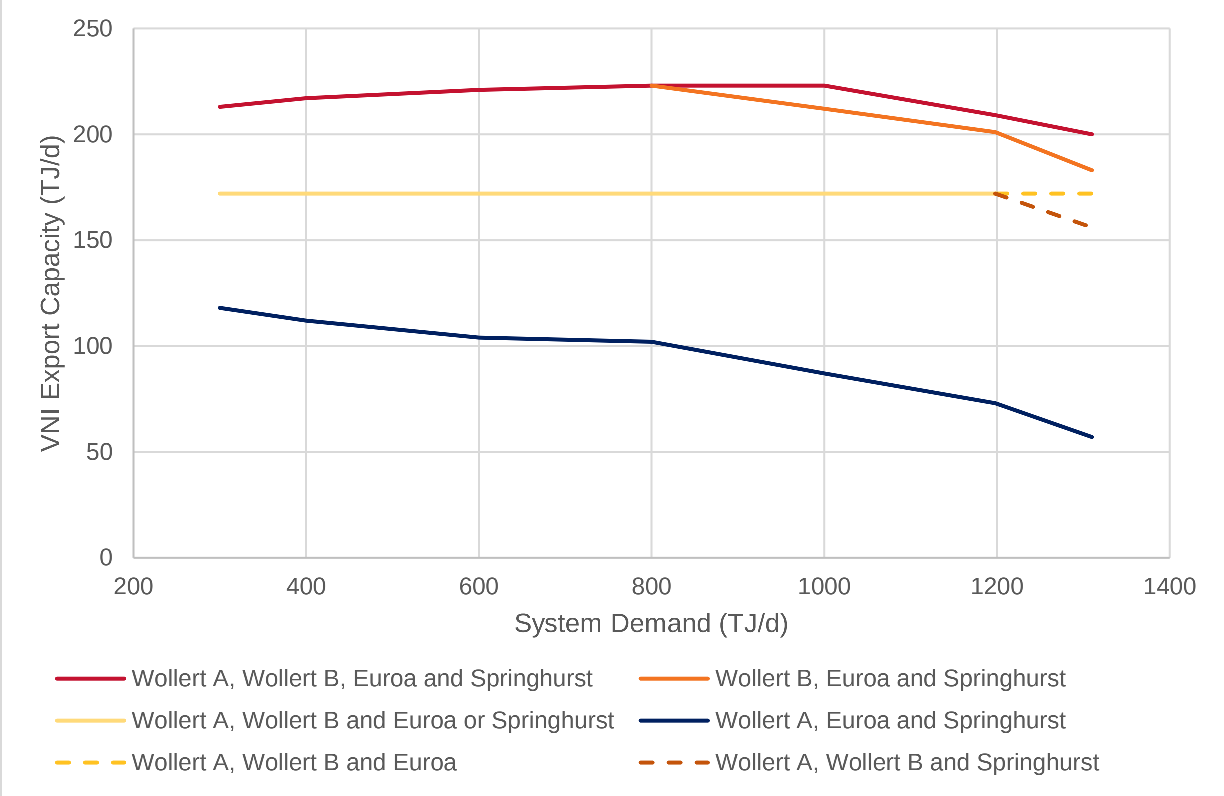


Figure 5 shows the VNI import capacity over the demand range for a variety of compressor combinations before completion of the VNIE Phase B project. The maximum import capacity for the VNI is 196 TJ/d.

Figure 5 VNI import capacity for winter 2017 – Pre VNIE Phase B Completion

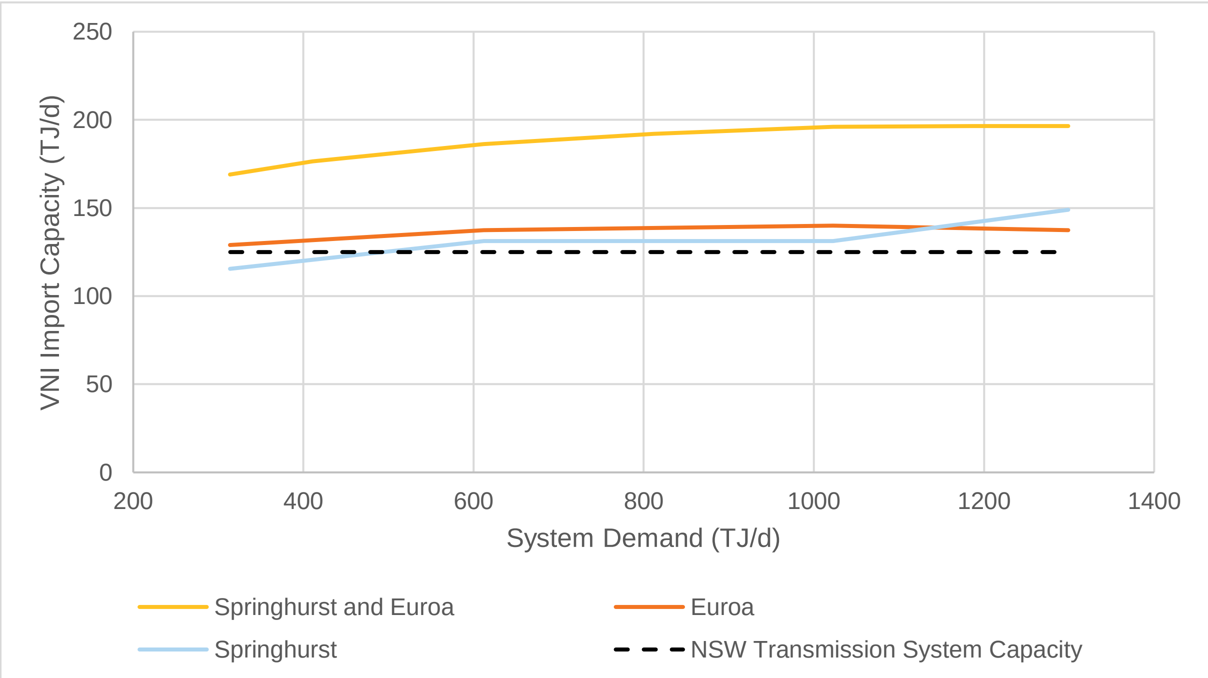
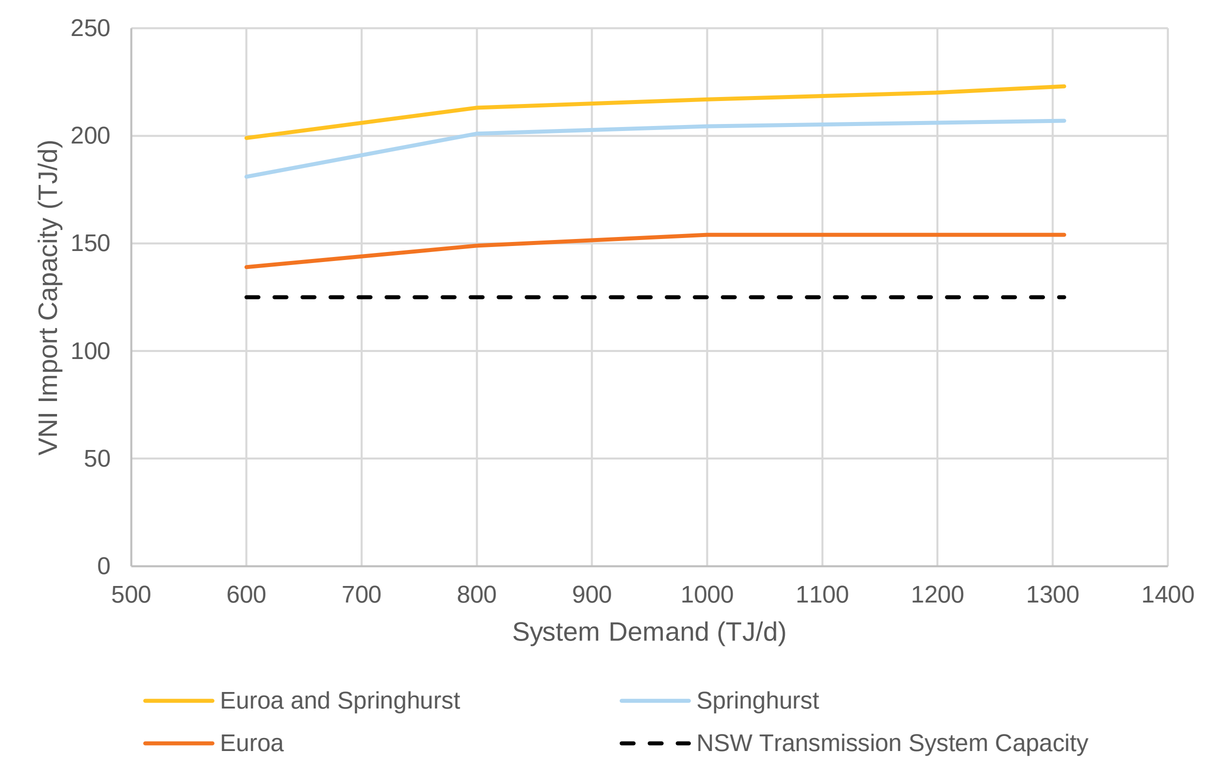


Figure 6 shows the VNI import capacity after completion of VNIE Phase B project. However, the capacity will be limited at 125 TJ/d, due to the New South Wales transmission system's capacity to supply gas at Culcairn.

Figure 6 VNI import capacity for winter 2017 – Post VNIE Phase B Completion



CHAPTER 2. OPERATIONS PLAN

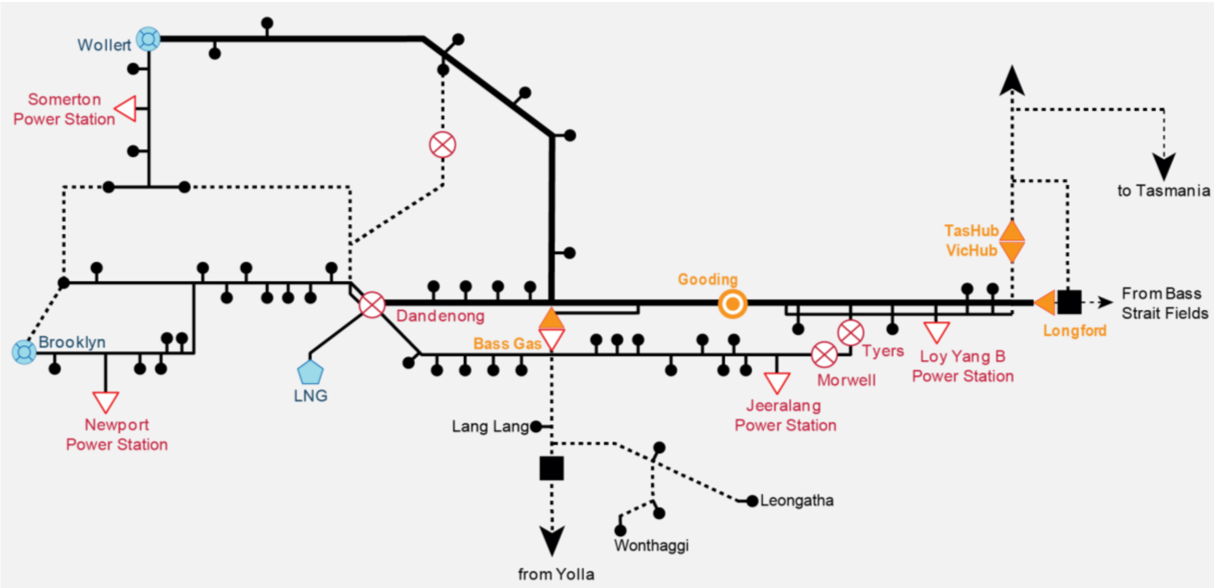
2.1 Transmission Operations

2.1.1 Longford to Melbourne Pipeline

Figure 7 includes:

- The LMP, which runs from Longford to Dandenong City Gate (DCG).
- The Pakenham to Wollert Pipeline (also known as the Outer Ring Main), which runs north from Pakenham to the Wollert City Gate and Wollert Compressor Station.
- The Lurgi Pipeline, which runs parallel to the LMP from the Tyers Pressure Limiter to the Dandenong Terminal Station, which is where DCG is located.

Figure 7 Longford to Melbourne Pipeline



Pipeline pressure

Pressure along the LMP is managed by balancing linepack within the DTS. If LMP injection facilities deviate from their schedule by over-injecting, it is possible for the pipeline pressure to get too high.

Where an imminent high pressure event is identified, AEMO will notify the Longford Gas Plant. The notification is to allow time for the Longford facility operator to take appropriate action and minimise the ramp down rate required. The Gooding compressors can be used to help move linepack from Longford to Melbourne if system conditions allow compressors to be run effectively.

AEMO will inform market participants of the approaching high pressure event by publishing a system wide notice (SWN), at the same time as it notifies the Longford plant.

Dandenong City Gate

On high system demand days, the DCG inlet pressure can approach its minimum operational target pressure of 3,300 kilopascals (kPa) as linepack is depleted along the LMP.[11] Maintaining this minimum operational pressure target is critical for ensuring Melbourne metropolitan demand is safely met.

[11] While the operational target is 3,300 kPa, the minimal operations pressure of the Dandenong City Gate is 3,200 kPa, as detailed in AEMO's Wholesale Market Critical Location Pressures, available at: http://www.aemo.com.au/Gas/Declared-Wholesale-Gas-Market-DWGM/Policies-and-procedures

Operational strategies to maintain the DCG inlet pressure above 3,300 kPa include:

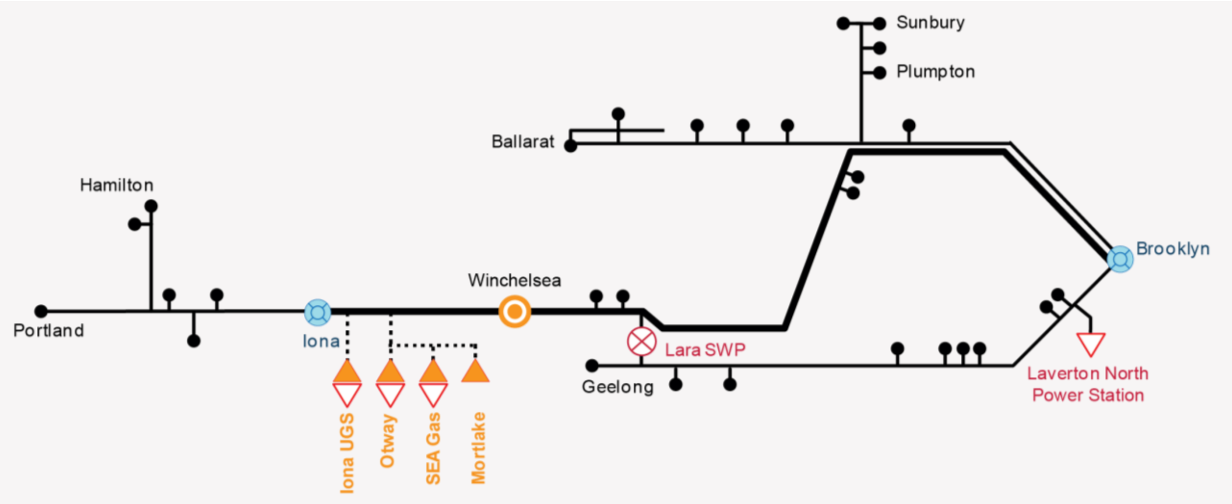
- Maximising SWP supply.
- Operating Gooding compressors.
- Injecting operational response LNG.
- Restricting or shutting down the Wollert Compressor Station (see section 2.1.3 for 'Prioritisation of Operational Response LNG' if this is required to support Culcairn exports).

2.1.2 South West Pipeline

Figure 8 includes:

- The SWP, which runs from Iona injection point to Lara City Gate.
- The Brooklyn to Lara Pipeline, which continues on from the SWP and extends from Lara to the Brooklyn City Gate.
- The Brooklyn to Corio Pipeline, which runs from Lara, near Geelong to the Brooklyn City Gate, south of the Brooklyn to Lara Pipeline.
- The Brooklyn to Ballan Pipeline, which runs from Brooklyn City Gate to Ballarat.
- The Western Transmission System (WTS), which runs from Iona to Portland.

Figure 8 South West Pipeline



For winter 2017, Port Campbell is expected to continue injecting into the DTS during the winter months, especially when total demand is greater than 800 TJ.

On peak demand days, flows on the SWP are expected to approach the transportation capacity. Strategies to maximise Port Campbell supply to Melbourne are crucial to meet the overall supply-demand balance.

High pressures in the SWP can affect the ability of the gas production plants to inject gas into the pipeline. If not managed, this can reduce supply, affect the system linepack balance, and potentially necessitate injections from other sources.

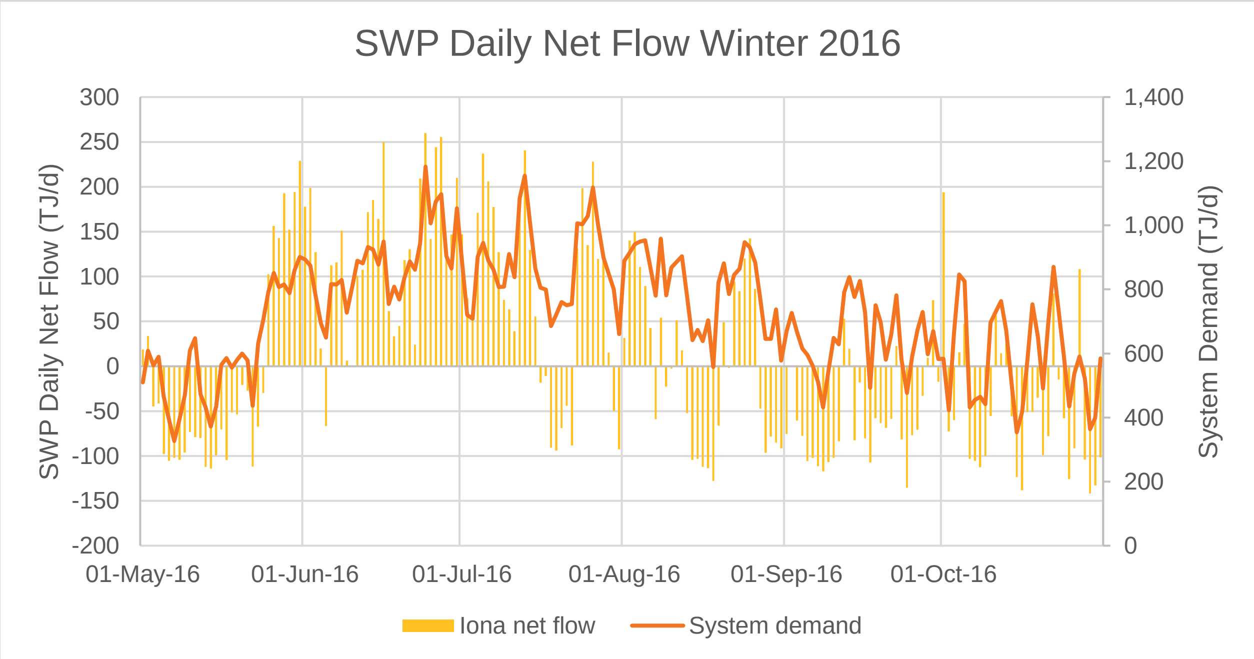
With the Winchelsea Compressor Station available, the maximum transportation capacity from Port Campbell to Melbourne is 413 TJ on a 1-in-20 demand day. An additional 20 TJ can be injected to supply the WTS, which makes the total injection capacity 433 TJ/d. The Winchelsea compressor can also be used to help move linepack from Port Campbell to Melbourne in a similar mode of operation to the use of the Gooding compressors on the LMP.

When Longford plant maintenance is conducted during the summer months, the DCG outlet pressure set point may be lowered to increase the SWP transportation capacity. This has been a successful plan for improving security of supply into Melbourne, but has limited capability during the winter. The DCG pressure must be higher in winter, due to the higher pressure drop that occurs when Melbourne metropolitan demand increases.

AEMO's monitoring showed that Iona UGS was depleted to about 50% of its capacity by the end of June 2016. In 2017, AEMO will continue to monitor Iona UGS levels to ensure gas will be available through the May to September winter period.

SWP exports had not previously been seen during the winter months. SWP injections were required consistently during the colder months of June and July. However during lower demand days in July and August (typically below 800 TJ) SWP exports (as shown in Figure 9) were scheduled in the market.

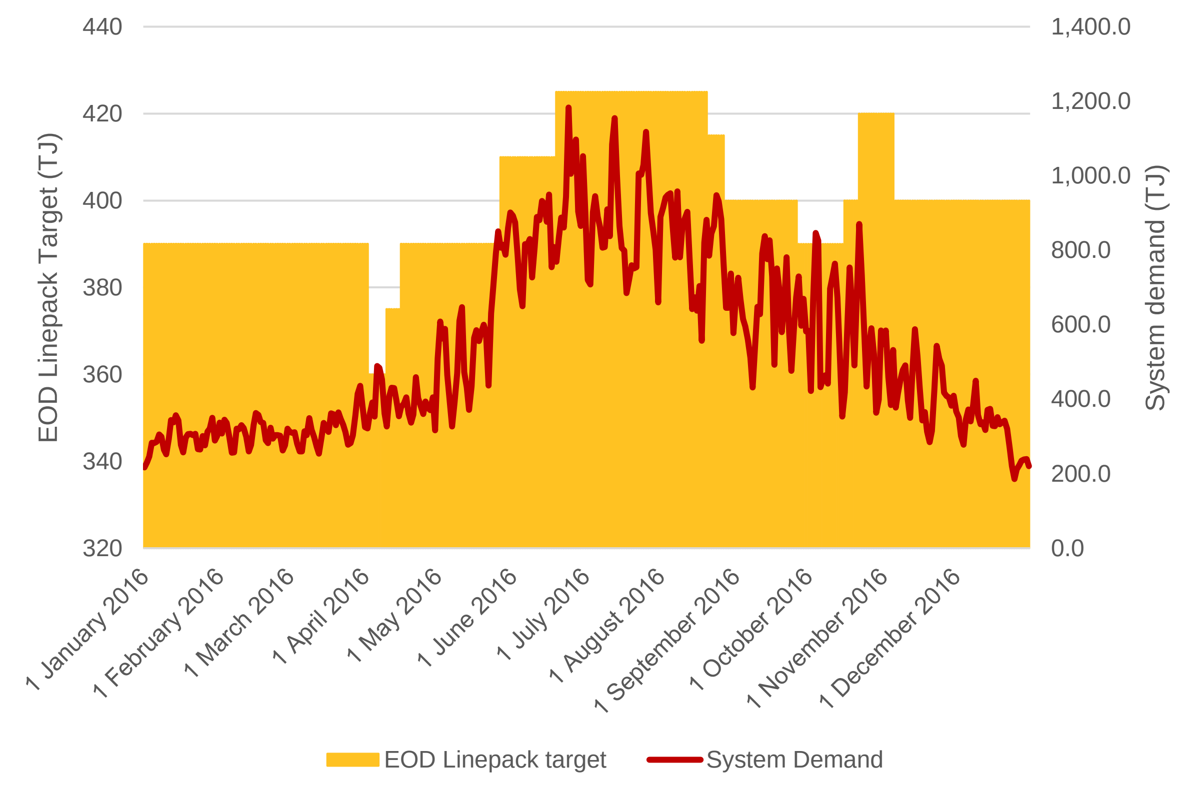
Figure 9 SWP Net Flows to Melbourne, Winter 2017



The SWP withdrawals created operational challenges in particular with regard to managing zonal linepack. There are two components to consider here; one is the high End of Day (EOD) linepack target required to support high demand and the other is the capacity of the Brooklyn Compressors.

During the winter months, the EOD linepack target is increased to ensure there is enough active linepack in the system to account for high instantaneous demand over the evening peak. The following chart shows the linepack target changing during peak demand periods.

Figure 10 End of Day (EOD) linepack target vs instantaneous demand



The linepack target is still required to be high in the later winter months due to high demand days. When Iona UGS is exporting during these periods, there is minimal usable linepack in the SWP. Therefore, most of this linepack is in the LMP and the VNI.

To enable more flexibility in managing the SWP linepack, AEMO will, as per section 5.2, send a market notice by the 4PM D+1 schedule if a change to the EOD linepack target is required due to the SWP being in net withdrawal. This adjustment in the EOD linepack target will be triggered by net withdrawals occurring on the SWP over multiple gas days. In this scenario, AEMO may reduce the EOD linepack target by up to 20 TJ if an assessment indicates this will not increase operating risk.

The Brooklyn Compressor Station has a maximum compressor ratio of 2.4; due to inner ring main pressures averaging between 2,500 and 2,650 kPa in winter, and BLP inlet pressures (Brooklyn Compressor Station discharge pressures) rarely increase above 6,400 kPa. This pressure is sufficient to satisfy system demand in the Geelong and Western regions, plus limited exports to Iona UGS.

Under this operating mode there is no usable linepack in the SWP and BLP. In this situation, pressures at Iona City Gate will be approximately 4,500 kPa. Iona compression is expected to be required to support WTS demand during winter, noting that temperatures in southwest Victoria can be lower than Melbourne.

Brooklyn to Ballan Pipeline

The Brooklyn to Ballan Pipeline runs from the Brooklyn City Gate to Ballarat, which is the highest demand point along the pipeline. During winter on peak demand days, a Brooklyn compressor is usually required to maintain minimum operational pressures at Ballarat.

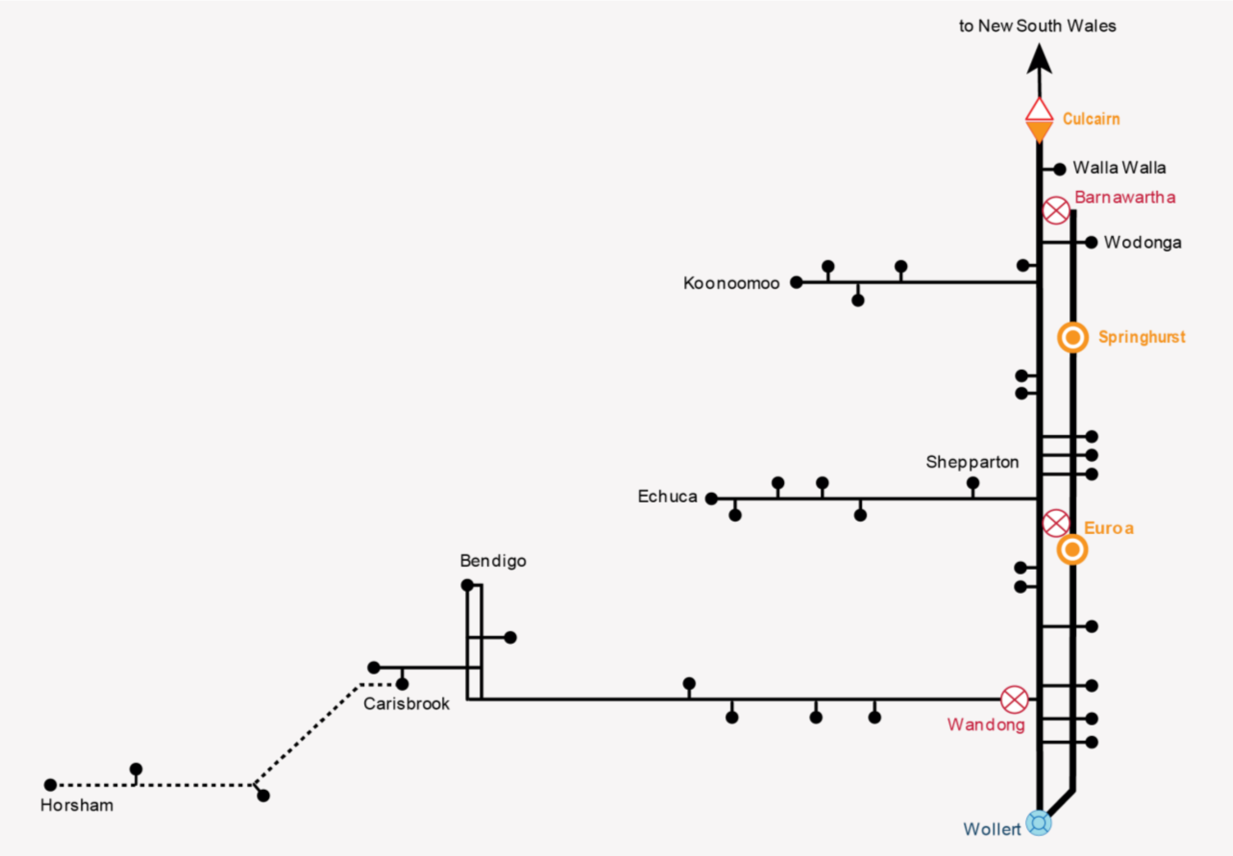
2.1.3 Victorian Northern Interconnect

The Victorian Northern Interconnect (VNI) includes:

- The major pipelines for transportation of gas to and from New South Wales via Culcairn.

- Wollert, Euroa and Springhurst Compressor Stations, which increase the transportation capacity along the VNI.
- Lateral pipelines to Bendigo, Echuca, Koonoomoo and Wodonga.

Figure 11 Victorian Northern Interconnect



VNI export

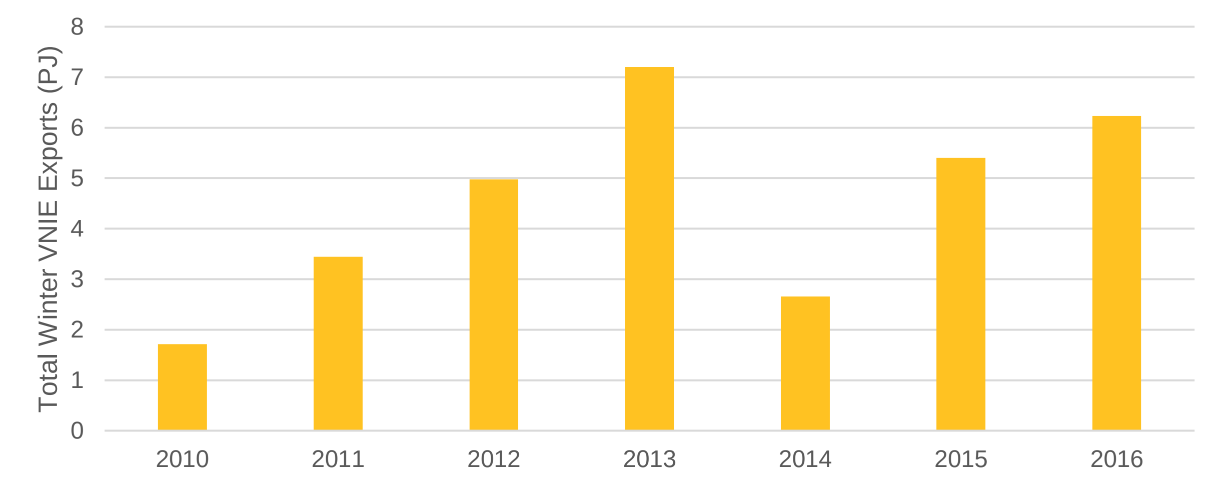
For winter 2017, VNI exports to New South Wales are expected to be similar to or less than 2016 due to the tighter supply and demand balance in 2017.[12]

Figure 12 shows historical VNI exports during winter since 2010, as well as forecast winter VNI exports for 2017:

- From 2010 to 2014, VNI exports increased steadily.
- In 2014, coal seam gas (CSG) wells were brought online to supply LNG plants in Queensland. The wells were brought online ahead of the LNG plants being commissioned, which meant additional gas supplies were temporarily provided to the interconnected east coast gas markets, reducing the need for VNI exports.
- In 2015, VNI exports increased again as LNG trains commenced operation.
- In 2016, VNI exports increased steadily including to support NSW demand and generation at Uranquinty Power Station.
- In 2017, VNI exports may be dictated by daily market conditions as participants balance their portfolios based on NEM and DWGM demand.

[12] AEMO. *2017 Gas Statement of Opportunities.* Available at: https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

Figure 12 Victorian Northern Interconnect export to New South Wales (PJ), winter 2010–17



Prioritisation of operational response LNG

On peak demand days, maintaining a high VNI linepack to support high exports can decrease the linepack available for Melbourne demand. If this occurs, LNG may be required to maintain the DCG inlet pressure above 3,300 kPa, while VNI export continues.

In the event that DCG inlet pressure is forecast to fall below the minimum operating pressure, AEMO will take the following steps, in the order of AEMO's response, to maintain system security:

1. Use Gooding compressors to shift linepack toward Melbourne.
2. Ensure all available system linepack from other pipelines have been exhausted to support pressures at DCG.
3. Schedule peak-shaving LNG at Dandenong up to the firm rate of 100 tonnes/hr (5.5 TJ/hr).
4. Reduce compression at Wollert Compressor Station to prioritise the supply of gas to Melbourne.
5. Schedule peak-shaving LNG at Dandenong up to the non-firm capacity of 180 tonnes/hr (9.9 TJ/hr).

If these steps are insufficient, AEMO may utilise the *Gas Load Curtailment and Rationing and Recovery Guidelines*.[13]

VNI flow direction changes

Although exports into New South Wales via the VNI are expected to increase in winter 2017, switching between injections and withdrawals can occur. Market participants may supply gas that has been sourced from the Queensland LNG producers, into the DTS to support winter peak demand.

Additional supply from Queensland may also be available on an unplanned basis. Production from CSG wells that typically supply the Gladstone LNG plants cannot be shut in without long-term impacts on their production rates. As a result, any reduction of LNG plant capacity for planned or unplanned maintenance may result in additional supplies being diverted to other markets, including the DWGM.

Imports into Victoria via the VNI can be assisted with the bi-directional compressors at Springhurst and Euroa. When the scheduled flow direction changes, the full pipeline capacity may not be available. The time taken to respond to any schedule changes depends on the magnitude of the change and the system conditions.

[13] AEMO, *Gas Load Curtailment and Rationing and Recovery Guidelines.* Available at: http://www.aemo.com.au/Gas/Emergency-management/Victorian-role

Impact of compressor availability

When compressors are unavailable due to planned or unplanned maintenance, the VNI export capacity is reduced. On a 1-in-20 system demand day:

- Without availability of the Springhurst Compressor Station, the projected VNI export capacity reduces by approximately 14%, from 200 TJ/d to 172 TJ/d.
- Without availability of the Euroa Compressor Station, the export capacity reduces by approximately 22%, from 200 TJ/d to 156 TJ/d.
- The greatest impact on VNI export capacity is seen when Wollert B Compressor Station is unavailable. Even if Wollert A, Euroa and Springhurst Compressor Station are available, the export capacity is reduced by 72%, from 200 TJ/d to 57 TJ/d.

2.2 Scheduling Constraints

Constraints can be initiated by AEMO or a facility operator, and are applied to:

- An individual Operating Schedule (OS), or
- Both the Pricing Schedule (PS) and OS.

If the application of a constraint is necessary, the constraint can be applied to:

- Injections, where the highest priced injection bid is removed first, and then the second highest bid, until the injections are reduced down to the constraint quantity.
- Controllable withdrawals, where the lowest priced withdrawal bid is removed first, and then the second lowest bid, until the withdrawals are reduced down to the constrained quantity.

If multiple bids set the market price, participants with Authorised MDQ are given priority. If multiple participants have Authorised MDQ, then they are prorated.

Each type of scheduling constraint is detailed below.

Supply and Demand Point Constraint (SDPC)

An SDPC is applied to restrict or specify energy flows at an injection or a withdrawal point. For example, if a facility operator advises AEMO that there will be planned or unexpected maintenance at an injection or a withdrawal point, an SDPC is applied to both the PS and OS at an injection point to the facility operator's specified quantity.

Directional Flow Point Constraint (DFPC)

A DFPC is used to limit net flows at a bi-directional supply point. Historically DFPCs have primarily been used to prevent net withdrawals at bi-directional meters where financial flows are allowed but physical net withdrawals are not possible.

DFPCs have been applied permanently on the VicHub, TasHub and SEA Gas bi-directional meters to prevent net withdrawals, as these facilities currently cannot physically withdraw from the DTS.

A DFPC is also used to limit a facility to a particular net rate during maintenance or other physical limitation occurring outside the DTS. For example, if one of the three compressors at the VNI is undergoing maintenance, a DFPC can limit exports at Culcairn injection and withdrawal meters to achieve a specific withdrawal rate.

Net Flow Transportation Constraint (NFTC)

An NFTC is applied to a collection of meters on a pipeline to prevent the transportation capacity being exceeded. For example, an NFTC may be applied to the SWP meters, which will limit the total net scheduled quantity on the SWP to its transportation capacity.

NFTCs have been applied to the OS only as per the *Wholesale Market Gas Scheduling Procedures*.[14]

Supply Source Constraint (SSC)

An SSC can be applied on a production facility located outside the DTS that supplies an injection meter. This may be useful where multiple facilities supply one injection meter. If one plant trips an SSC can be applied to that plant, so that injection bids from participants obtaining gas from the affected facility can be constrained.

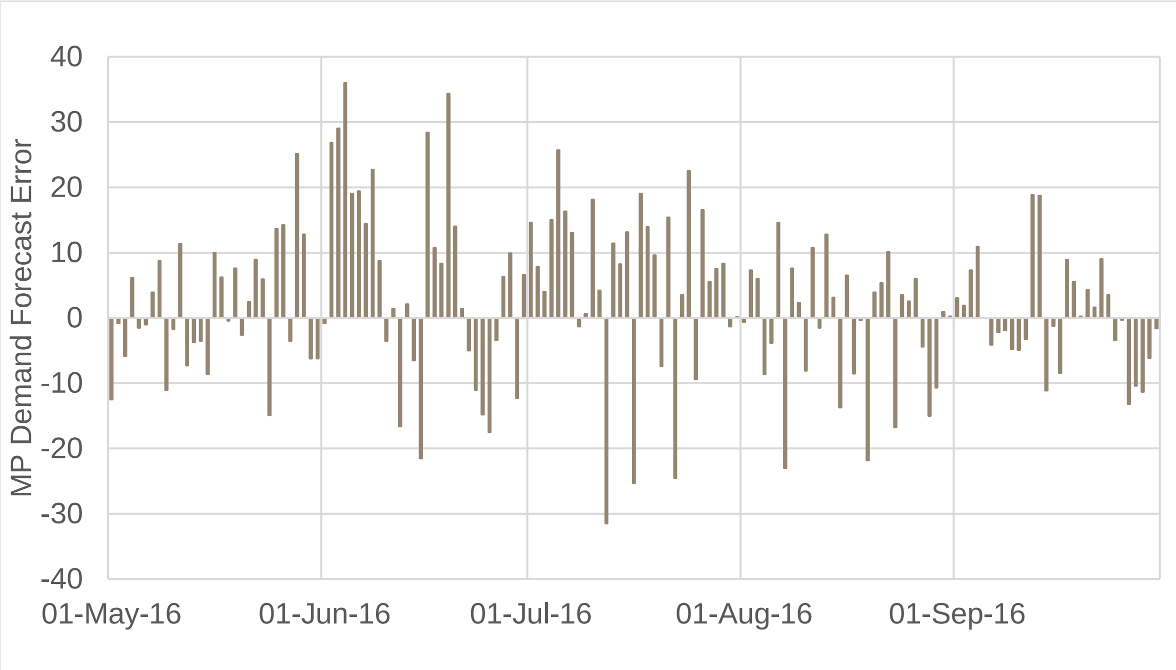
To date, no participants have registered to use an SSC. Therefore it is not anticipated that an SSC will be applied in winter 2017.

2.3 Demand forecast management

Demand forecast accuracy is critical when scheduling gas during winter.

Figure 13 displays the difference between market participants' aggregated forecast demand and actual demand during winter 2016.

Figure 13 Difference between market participants' forecast and actual demand (TJ), winter 2016[15]



This demonstrates that during winter, market participants have tended to over-forecast total demand.

If gas demand is over-forecast:

- Too much gas may be stored in a pipeline, which reduces scheduling flexibility later in the gas day.
- Oversupply can cause gas injections to be backed-out, which may cause injection plants to trip, threatening supply availability.
- The market price can decrease later in the gas day.
- Facility operators may not meet their injection schedules resulting in deviations.

If gas demand is under-forecast:

- Scheduled supply can be insufficient to meet the actual demand.

[14] AEMO, *Wholesale Market Gas Scheduling Procedures (Victoria)*, 4 May 2016. Available at: http://www.aemo.com.au/Gas/Declared-Wholesale-Gas-Market-DWGM/Policies-and-procedures

[15] Forecast and actual compared for the 10:00 pm schedule interval.

- A system withdrawal point could breach its minimum operating pressure, creating a public safety risk.
- Operational response LNG may be scheduled to support system pressures, which comes at a cost to the market.

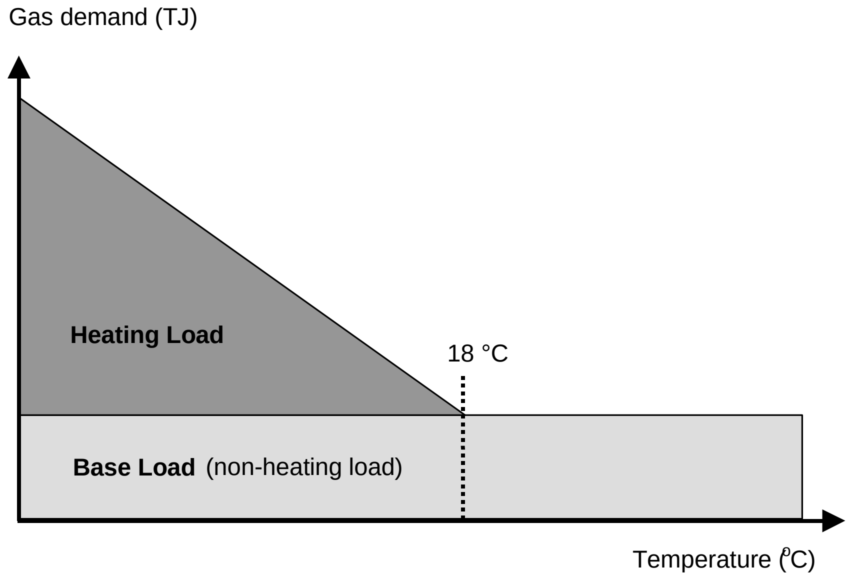
System demand

Market participants forecast both system and site-specific demands, which are aggregated to produce total demand forecast quantity.

System demand includes base load and heating load. Base load typically does not change throughout the year, but heating load depends on temperature. In winter, there is greater demand variance due to heating load and its relationship to temperature variance (see Figure 14).

Site-specific demand includes GPG and industrial sites.[16]

Figure 14 Gas demand and temperature relationship



Heating load can be seen as part of a system demand as soon as the average temperature drops below 18º Celsius.

Forecast uncertainties

The accuracy of demand forecasts in winter can be impacted by variables such as weather (temperature, wind, sunshine, or previous day's temperature) and sudden GPG demands.

Despite the uncertainties, there are market mechanisms to ensure the supply and demand balance is met throughout the gas day:

- Intraday scheduling process to take into account the DTS' current pressures, as well as updated market participants' aggregated total demand forecast.
- AEMO may override market participants' aggregated total demand forecast, in accordance with the *Victorian Wholesale Gas Demand Override Methodology*.[17]

[16] Industrial sites are also referred to as tariff D withdrawal points. This is a system withdrawal point or distribution delivery point at which gas is withdrawn at a rate of more than 10 gigajoules (0.01 TJ) in any hour or more than 10 TJ in any year.
[17] AEMO. *Victorian Wholesale Gas Demand Forecast Methodology.* Available at: http://www.aemo.com.au/Gas/Declared-Wholesale-Gas-Market-DWGM/Policies-and-procedures

Intraday schedules

Scheduled injection and withdrawal quantities can deviate more during winter compared to summer. This may be due to sudden weather changes, resulting in inaccurate demand forecasts. Schedule deviation may exist any time of the year due to a sudden injection plant outage, DTS asset outage, or sudden changes in site-specific demands.

These variations can result in intraday schedule deviations and cause the system to experience higher than expected linepack variation. To maintain system security, the MCE takes into account current system pressures, updated demand forecasts and facility injections at every intraday scheduling intervals. The MCE then adjusts the supply and demand balance to ensure the end-of-day linepack target can be met.

These rebalancing actions, are required to account for under and over-forecasts, can affect the market outcome:

- When demand has been over-forecast in previous scheduling intervals, injections are reduced for the following scheduling interval, potentially decreasing the market price.
- If demand has been under-forecast in previous scheduling intervals, injections are increased for the following scheduling interval, potentially increasing the market price.

Therefore, improved accuracy of market participants' intraday demand forecasts can reduce the likelihood of system congestion and a volatile market price.

Demand forecast override

If the market participants' demand forecast is too high or low relative to AEMO's demand forecast, an override quantity may be subtracted from (or added to) the market participants' aggregate demand forecast. This ensures an appropriate amount of gas is scheduled to maintain a safe level of linepack reserve and system security.

The override quantity is calculated based on the *Victorian Wholesale Gas Demand Override Methodology*.[18] It considers variables such as:

- Beginning-of-day linepack level (high, on target or low).
- Profile type (light, average or heavy).[19]
- Demand override adjustment factors.

The variables are then used to calculate upper or lower threshold limits for each scheduling interval. The threshold limit is compared to the difference between AEMO's and market participants' total demand forecasts. Then, an adjustment is made to the market participants' aggregate demand forecast so it is within the upper or lower threshold limit.

2.4 Gas Market Interaction

AEMO anticipates that Victoria will continue to supply gas to other markets during winter 2017. The market interactions are largely due to gas demands in the STTM and interstate GPG demand. These are not expected to cause any threat to system security if there are no large changes into DTS flows during the gas day and Iona UGS inventory is not drawn down to the point that winter supply to Victoria is threatened.

[18] AEMO, Demand Override Methodology. Available at: https://www.aemo.com.au/Gas/Declared-Wholesale-Gas-Market-DWGM/Policies-and-procedures

[19] Profile type is determined by obtaining a profile value. Profile value is the difference between total hourly withdrawal and injection for 16 hours.

2.4.1 Short Term Trading Market

Victoria supplies gas to the STTMs:

- Adelaide hub via the SEA Gas Pipeline. The SEA Gas Pipeline and Moomba to Adelaide Pipeline (MAP) are interconnected which means flows on SEA Gas can support demand on the MAP.
- Sydney hub via the EGP and the VNI (which joins the MSP). The EGP is also interconnected with the MSP at Wilton.

Contingency Gas

The greater risk of supply tightness on the east coast interconnected gas markets, which AEMO identified in the *Energy Markets for a Changing Environment* project[20], has eventuated with four contingency gas events in 2016. These were:

- 13 January – 30 TJ shortfall was expected due to the compressor issue on the EGP. Participant renominations were sufficient to offset the expected shortfall.
- 1 October – An expected shortfall due to Longford experiencing electrical issues which resulted in a full plant shut down. Participant renominations of 21 TJ to the MSP plus the ramp up of flows from Longford to the EGP were sufficient to offset the expected shortfall.
- 9 November – 16 TJ shortfall was expected due to the compressor issue on the EGP. Participant nominations and MOS Increase on the MSP were sufficient to offset the expected shortfall.
- 24 November – 30 to 50 TJ shortfall was due to Longford plant issue reducing injections into the EGP. Participant renominations were sufficient to offset the expected shortfall.

As well as facilitating STTM conferences during Contingency Gas events, AEMO participates in the conferences for the Sydney hub as the DTS pipeline operator, providing information on DWGM scheduling outcomes and the most up-to-date DTS export capacity for VNI.

2.4.2 Gas Supply Hub

The Wallumbilla Gas Supply Hub has become an alternate market to source additional gas supplies for the interconnected eastern Australian gas markets. In winter 2016 there was evidence that Participants:

- Purchased gas at the Wallumbilla Gas Supply Hub
- Transported gas to Sydney, via the MSP, which allowed gas from Longford to be reserved to supply Victorian demand.
- Transported gas to Adelaide, via the MAP, which allowed Port Campbell supply to be reserved to supply Victorian demand.

Winter 2017 may again see additional gas supplies purchased at the Wallumbilla Gas Supply Hub offsetting gas demand from Adelaide and Sydney STTM hubs. In addition, import flows through the VNI (of up to 125 TJ/d) may be made by participants. These flows will largely depend on the portfolio position of participants and therefore cannot be predicted with any certainty.

[20] AEMO. *Gas Wholesale Consultative Forum*. Available at: http://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Wholesale-meetings/Gas-Wholesale-Consultative-Forum.

CHAPTER 3. PEAK DAY MANAGEMENT

- When a high demand day is forecast, Longford injection profiling can be used to increase linepack availability during the evening peak.
- Where system pressures are forecast to fall below defined operational limits, AEMO may provide notice of a threat to system security, and take action to alleviate the threat.
- AEMO will communicate relevant information to participants.

AEMO aims to operate the DTS in a normal operating state, as defined in the *Wholesale Market System Security Procedures.*[21] A normal operating state includes maintaining system pressures and flows within defined operating limits.

3.1 Injection profiling

On peak demand days, conserving or increasing system-usable linepack before the evening peak is an effective way to reduce the likelihood of a threat to system security. When a peak demand day is forecast, AEMO can improve system security by scheduling more gas injections into the DTS early in the gas day, and balancing this with less gas later in the day.

The total quantity injected for the day is the same, so the market is not impacted by this process.[22] However, the gas available before and during the evening peak is increased. This plan may be used when the total Day +1 demand forecast exceeds 1,150 TJ. AEMO consults Longford and VicHub facility operators before scheduling profiled injections.[23]

3.2 Threat to system security

AEMO must monitor operational conditions to identify any material schedule deviation or forecast that may cause a threat to system security. This includes:

- Rapidly increasing demand due to deteriorating weather conditions.
- Unscheduled DTS asset outage.
- A transmission pipeline incident and/or a gas supply incident.

3.2.1 Notice of threat to system security

If AEMO identifies a threat to system security, it notifies market participants as soon as possible, communicating:

- The nature and magnitude of the threat, including the likely duration of the threat and the shortfall in gas supplies likely to occur during that period.
- Whether AEMO needs to intervene in the market to avert the threat, and the time by which intervention will be required if the threat has not subsided.
- The DTS system withdrawal zones in which the threat is likely to be located.

AEMO's tiered approach to managing a threat to system security is set out in section 3.2.2. This approach adopts scheduling solutions based on the time until a minimum pressure is breached and the quantity of gas required (vs. gas available in the market).

AEMO may also issue a notice requiring participants to provide information about their capability to inject or withdraw non-firm, or off-specification, gas. This information will be used by AEMO to help

[21] AEMO. *Wholesale Market System Security Procedures (Victoria).* Available at: http://www.aemo.com.au/Gas/Declared-Wholesale-Gas-Market-DWGM/Policies-and-procedures.
[22] Profiling injections does not impact either imbalance or deviation payments.
[23] Injection profiling is available at the Longford injection point.

determine options for alleviating the threat. AEMO may also request information regarding participants' ability to voluntarily reduce industrial load if required.

3.2.2 Responses to a threat to system security

After AEMO identifies a threat to system security, a response to avert the threat is required. The following responses are available to AEMO, which are listed in the order of AEMO's response.[24]

1. Market response

Under some circumstances, AEMO may identify a threat to system security that does not require immediate action, as the threat can be alleviated through a market response.

In this case, AEMO will:

- Provide details to participants of the threat to system security.
- Advise participants of actions they should take (or refrain from taking) for the threat to subside. These actions could include re-bidding to increase or decrease the amount of gas injected or withdrawn at particular injection or withdrawal points within the DTS.

2. Out of merit order gas injection in the next Operating Schedule

If a market response is unable to alleviate a threat to system security, AEMO can schedule out of merit order injections in the OS at the next regular schedule. Out of merit order gas can be injected at any injection point in the system, to ensure minimum contractual pressures are maintained throughout the DTS.

On peak demand days, pressures at key demand centres can fall rapidly. In this case, operational response LNG injections are the most effective method to alleviate the threat.

3. Publishing ad hoc operating schedules

If a market response is unable to alleviate a threat to system security, and an immediate rebalancing action is required, an ad hoc OS can be published by AEMO. These ad hoc schedules allow both normal merit order and out of merit order gas (such as operational response LNG) to be injected into the DTS as soon as possible to alleviate the threat. An ad hoc schedule is a market intervention.

4. Directing participants to inject or withdraw gas

If a facility has gas available for injection, or has the ability to withdraw gas, AEMO may direct participants to inject or withdraw, even if bids have not been made for that gas (which would not allow it to be scheduled in an ad hoc schedule). This direction to inject can extend to non-firm supply or off-specification gas. AEMO considers critical factors such as potential public safety implications or potential damage to capital equipment.

5. Curtailment

AEMO may enact curtailment in accordance with the *Gas Load Curtailment, Gas Recovery and Rationing Guidelines*[25], where the threat to system security cannot be alleviated through other means.

3.2.3 End of a threat to system security

When AEMO determines that a threat to system security no longer exists, it will send an SWN to market participants to inform them there is no longer a threat.

[24] Note that points 3, 4 and 5 above are interventions under the National Gas Rules (NGR).

[25] AEMO *Gas Load Curtailment and Gas Rationing Recovery Guidelines.* Available at: http://www.aemo.com.au/Gas/Emergency-management/Victorian-role.

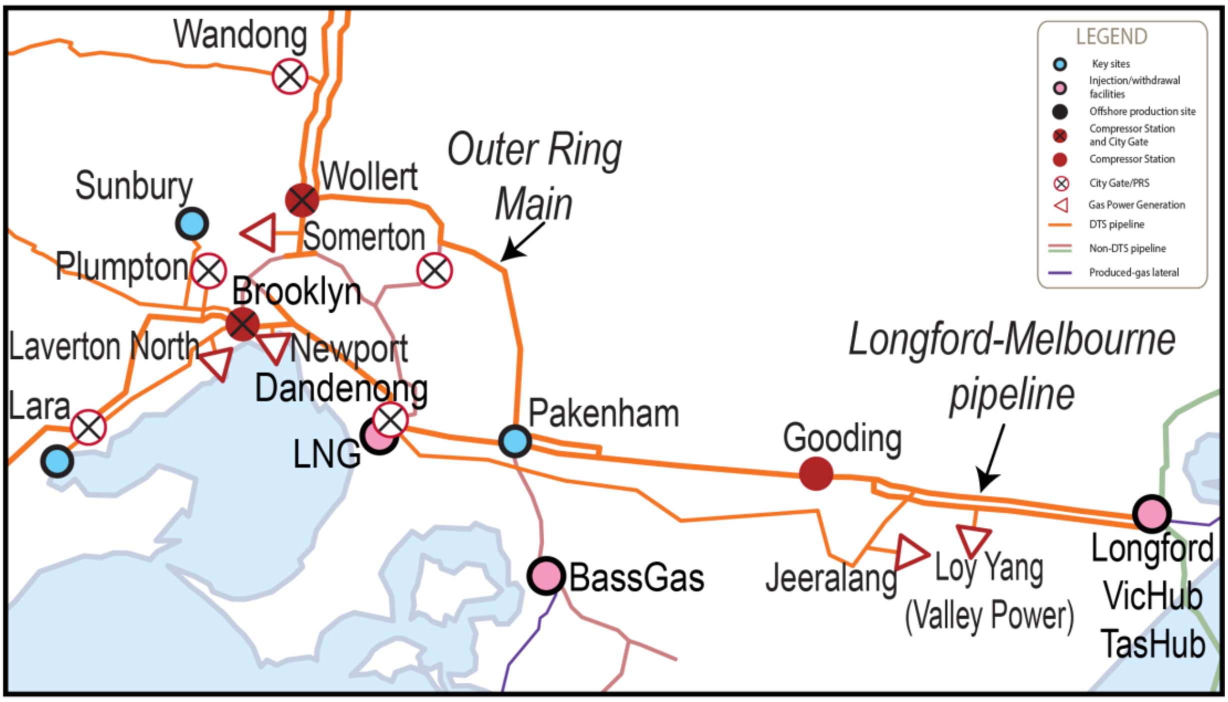
CHAPTER 4. SUPPORTABILITY OF GAS POWERED GENERATION

The closure of the coal-fired Hazelwood Power Station is expected to drive an increase in GPG consumption in the DTS. There are five GPG power stations directly connected to the DTS, as shown in Figure 15. These are:

- Valley Power
- Jeeralang
- Newport
- Laverton
- Somerton

Each of these GPG units have an impact on the operation of the DTS due to their location and the large quantity of gas (up to 23 TJ/h) the simultaneous operation of all DTS units can withdraw.

Figure 15 Map of DTS connected GPG sites



4.1 GPG Demand

The maximum hourly demand from all DTS connected GPG units is about 23 TJ/hr. The closure of the Hazelwood power station is forecast to increase GPG usage from 4 PJ in 2016 to 18.8 PJ in 2017 as shown in Table 8. Since the closure of the Hazelwood Power Station in March, DTS connected GPG units have been observed to run most days.

GPG consumption forecasts published in the Winter Plan use the GPG forecast from the 2017 VGPR.

Table 8 Historical Annual Gas Consumption (PJ)

	2010	2011	2012	2013	2014	2015	2016	2017*
Annual system consumption	220	217	211	200	195	208	204	196
Annual GPG Consumption	8	8	3	3	4	3	4	18.8
Total Annual Gas Consumption	228	225	214	203	199	211	208	214.8

Source: *Forecast as per 2017 VGPR, p 19&20.

The forecast GPG consumption of 7.9TJ in winter 2017 from 1 May to 30 September, as detailed in Table 9, is 42 per cent of the expected increase in GPG for 2017.

Table 9 Forecast Monthly Gas Consumption for 2017 (PJ)

	May	June	July	Aug	Sep	Total
System consumption	21.9	25.4	28.1	25.5	18.1	119
GPG Demand	1.0	0.4	2.8	2.3	1.4	7.9
Total Gas Consumption	22.9	25.8	30.9	27.8	19.5	126.9

Source: 2017 VGPR, p 22.

The quantity of gas that can be supported on a peak day is discussed in the next section.

4.2 Peak day GPG demand

The 2017 VGPR modelled GPG demand of 110 TJ/d occurring on a peak winter day. DTS-connected GPG units have historically run as peaking stations during times of high electricity demand, or during baseload generator outages.

The DTS has limited capacity to support GPG demand during winter, because:

- Instantaneous GPG hourly demand can be high, and can reduce linepack levels quickly.
- Some GPG loads (such as the Laverton North Power Station) require Brooklyn compression to supply gas if there are insufficient injections into the SWP at Port Campbell.
- GPG can come online at short notice, due to events in the NEM including unplanned outages of baseload generators. Unforecast GPG demand that starts during the gas day reduces the time and gas supply options available to increase DTS injections so the end of day linepack target can still be reached.

The winter GPG profile from the 2017 VGPR shows:

- High rates of generation from the GPG units from approximately 5:00pm to 8:00pm to support the evening peak electricity load.
- Approximately 110 TJ/d of DTS-connected GPG (total demand 1,308 TJ/d on a 1-in-2 peak day).

This analysis assumes all GPG load is forecast at the start of the gas day, and shows that to support the modelled GPG profile on a 1-in-2 peak demand day:

- No operational response LNG would be required if there were no Culcairn exports.
- 50 TJ of firm rate operational response LNG injections would be required to support the GPG demand if there is 150 TJ of coincident Culcairn exports.

GPG demand forecast uncertainty means AEMO must be prepared day-to-day to ensure enough supply capacity is available to meet minimum operating pressures throughout the DTS.

If the modelled scenario for the 1-in-2 peak day GPG demand profile was to occur on a 1-in-20 peak system demand day of 1,310 TJ/d (total demand 1,420 TJ/d):

- 65 TJ of firm rate operational response LNG injections would be required to maintain critical pressures.
- Wollert compression would need to be carefully managed over the evening peak to maintain an appropriate level of linepack near Melbourne.
- No Culcairn exports could be supported, which may impact non-DTS connected GPG demand (particularly the Uranquinty Power Station).

4.3 Unforecast GPG demand

The ability of the DTS to support this GPG load is drastically reduced if the load is unforecast, because there is insufficient usable linepack. Depending on the location and magnitude of the GPG load that is unforecast, it is possible that either:

- Extra operational response LNG injections, and potentially non-firm LNG, would be required.
- Critical supply pressures in metropolitan Melbourne could be breached, threatening supply within the distribution networks. This would lead to AEMO issuing curtailment instructions to GPG sites as per the *Gas Load Curtailment and Rationing and Recovery Guidelines*.[26]

It is critical to the normal operation of the DTS and the DWGM that participants accurately forecast GPG demand. If not, there is an increased likelihood of a threat to system security and AEMO using abnormal market processes such as operational response LNG or ad hoc schedules to balance gas supply and demand.

4.4 Managing GPG Demand

4.4.1 Longford to Melbourne Pipeline

Valley Power, Jeeralang, Somerton and Newport power stations all directly consume gas from the LMP. Laverton North PS requires Brooklyn compression to be operated to support its load, which also consumes linepack from the LMP, if there is not sufficient injections into the SWP at Port Campbell.

Given the difficulties in accurately forecasting GPG demand, it is important to maintain sufficient usable linepack in the LMP to account for any unforecast load. Operational strategies to support forecast or unforecast GPG are the same as those employed to maintain DCG minimum inlet pressures, as set out in section 2.1.1.

Specific Valley Power and Jeeralang Operational Strategy

There is a site specific strategy for:

- Jeeralang Power Station, which is supplied from the Lurgi Pipeline from the LMP via and Tyers Pressure Limiter and Morwell City Gate.
- Valley Power which is supplied directly from the LMP.

The Jeeralang and Valley Power power station offtakes are upstream of Gooding Compressor Station. Therefore unforecast GPG demand from Valley Power or Jeeralang can quickly lower pressures in the section of pipe between Longford and the Gooding Compressor Station.

If the Gooding Compressor Station is already operating, the suction pressure may already be approaching its minimum operating pressure of 4,500 kPa. If pressures upstream of the Gooding Compressor Station are decreasing too quickly, Gooding compressor engine speed may need to be lowered. This effectively reduces the available LMP gas flow rate to supply Melbourne.

[26] AEMO, *Gas Load Curtailment and Rationing and Recovery Guidelines.* Available at: http://www.aemo.com.au/Gas/Emergency-management/Victorian-role

4.4.2 South West Pipeline

Net Iona withdrawals are impacted by the Laverton North and Newport power stations, due to the location and high hourly rates of these GPG units. The GPG units and the impact they have on SWP withdrawal capacity are:

- 1 TJ of Laverton North Power Station demand reduces SWP withdrawal capacity by 1 TJ.
- 10 TJ of Newport Power Station demand reduces SWP withdrawal capacity by 1 TJ.

The impact of Laverton North is due to the current configuration of Brooklyn Compressor Station. The compressors are connected to the Brooklyn Corio Pipeline, which then flows into the Brooklyn to Lara Pipeline once sufficient pressure has built up in the Brooklyn Corio Pipeline through the Lara City Gate.

As Laverton North is connected to the Brooklyn Corio Pipeline, while it is in operation it draws down the pressure in the Brooklyn Corio Pipeline, which prevents gas flow into the Brooklyn Lara Pipeline to support withdrawals at Port Campbell.

4.4.3 Monitoring DTS connected GPG

Participants forecast GPG demand in the NEM Pre-Dispatch and in the DWGM as site specific forecasts. AEMO monitors these forecasts to ensure they are consistent and that any known increase in GPG forecast can be supported by the DTS. In addition, gas consumption by DTS connected GPG units can be monitored in real time through the AEMO System Control and Data Acquisition (SCADA) system. This enables AEMO to know if any of these GPG units begin operation.

As the NEM operates on five minute dispatch intervals, the NEM can incentivise GPG to come online unforecast in the DWGM if either a sufficiently high NEM price occurs or if it is required to cover a portfolio position (for example due to unexpected loss of other generation units).

The DWGM operates using schedules (and reschedules) at 6AM, 10AM, 2PM, 6PM and 10PM for the current gas day. Updates to participant inputs close an hour before the start of the scheduling interval. This means that the potential exists for participants to be unable to provide additional GPG gas supply for up to five hours (from one hour before the next schedule until the following schedule is issued). The following process by AEMO's are critical:

- Monitoring of NEM Pre-Dispatch and participant withdrawals through SCADA will be critical on high demand days throughout winter following the closure of the Hazelwood Power Station. This is to ensure sufficient linepack is available to support GPG operation.
- The AEMO Gas Control Room will notify the NEM Control Room of any issues within the Victorian system that may lead to DTS connected GPG units having insufficient gas supply.
- Contacting participants to clarify the intended operation of their GPG units.

AEMO can use the following operational responses to manage unforecast GPG:

- Demand Override – AEMO can apply the demand override methodology to total demand. Total demand includes system demand and site-specific demand from GPG units. Therefore a demand override can be implemented to account for unforecast GPG in the hour between the close of participant inputs and when a schedule is published. This same process can also be used in the event of a threat to system security and AEMO's publication of an ad hoc schedule to account for unforecast GPG demand.
- If unforecast GPG demand causes a threat to system security, it can be managed through AEMO's responses to a threat to system security (detailed in section 3.2.2):
  - Schedule operational response LNG to support Melbourne demand.
  - Produce an ad hoc schedule.
  - Direct gas injections into the DTS (if an ad hoc schedule will not provide sufficient gas supply to resolve the threat).

– Curtailment as per the *Gas Load Curtailment and Rationing and Recovery Guidelines*.[27]

Four of the five DTS connected GPG units are able to switch to liquid fuel in the event of insufficient gas supply. Therefore, if AEMO needs to curtail gas supply to these units, they will have the option of continuing to run in the NEM using alternate fuels. The AEMO Gas Control Room will consult with the NEM Control Room prior to curtailing DTS connected GPG units.

This strategy aims to reduce the impact of unforecast GPG on AEMO's operation of the DTS during high demand periods.

4.4.4 Monitoring non-DTS connected GPG

AEMO monitors non-DTS connected GPG demand that is forecast in the NEM Pre-Dispatch. By monitoring these flows, AEMO is able to determine whether injections or withdrawals are more or less likely to occur:

- For exports via Culcairn to support Uranquinty Power Station operation.
- For imports via Culcairn, whether these could be impacted by the operation of Uranquinty.
- For injections into the SWP at Port Campbell when the Mortlake Power Station is **not** operating.

Monitoring demand at these GPG units enables AEMO to anticipate gas flows into and out of the DTS.

There is another Victorian GPG unit at Bairnsdale that is not connected to the DTS. As such the gas supply to this power station is an operational responsibility for the EGP. Gas usage by the Bairnsdale Power Station is low relative to the overall EGP flow to New South Wales and the Australian Capital Territory, so it does not usually have a material impact on AEMO's assessment of gas flows.

4.4.5 Interaction with other National Electricity Market Regions

New South Wales

Gas supplies for the Tallawarra Power Station are transported from Victoria along the EGP, and supplies for Uranquinty GPG are often transported along the VNI.

These peaking stations have similar operating behaviour to GPG units in Victoria, as their gas demand depends on NEM conditions.

South Australia

Gas supplies for South Australian GPG units are transported toward Adelaide along the SEA Gas Pipeline from the Port Campbell region, including from Iona UGS. The SEA Gas Pipeline is connected to the MAP that enables gas to flow north from Adelaide. Therefore all GPG units (including Torrens Island, Quarantine, Pelican Point, Osborne and Dry Creek power stations) in South Australia can be supplied with gas from the Port Campbell region or from Moomba, subject to pipeline capacity limits.

Tasmania

Tasmania has been importing gas from Victoria via the TGP to operate the Tamar Valley Power Station since it returned to service in January 2016. Tamar Valley GPG operation reduced during winter 2016 and it is expected that this will occur again during winter 2017 when Tasmanian "run of river" hydro generation increases.

AEMO does not expect this to have a material impact on gas supply for Victoria during winter 2017. Should Tamar Valley GPG remain in service over the 2017 winter period, AEMO will monitor the overall gas supply-demand balance in southeast Australia.

On peak gas demand days for the DTS, there is sufficient gas (including TGP linepack) to supply demand in both Victoria and Tasmania including fuel for Tamar Valley GPG.

[27] AEMO, *Gas Load Curtailment and Rationing and Recovery Guidelines.* Available at: http://www.aemo.com.au/Gas/Emergency-management/Victorian-role

In the event sustained high gas demand or a major supply outage at the Longford Gas Plant, TGP linepack may require additional management to ensure that Tasmania gas supply is secure.

CHAPTER 5. COMMUNICATIONS

AEMO has procedures in place to ensure consistent communications with market participants regarding events that may affect operational and scheduling decisions.

5.1 Market Information Bulletin Board

The Market Information Bulletin Board (MIBB), as per the Wholesale Market Electronic Communication Procedure, is the primary source of all information about the DWGM including all System Wide Notices (SWNs) and reports.

5.2 System Wide Notices

AEMO provides SWNs to communicate operational issues to the market. SWNs are posted on the MIBB. These are also sent via SMS and/or email to each participants' registered contacts.

Common events that AEMO will communicate to the market include, but are not limited to, the following:

- Gas Quality SWN - Notification of gas quality excursions.
  - The market is notified within 25 minutes after a gas quality parameter excursion initially occurs.
- Scheduling SWN - Application of constraints that reflect physical limitations of facilities or pipelines (such as for maintenance or a pipeline that is constrained).
  - Facility constraint - The market is notified shortly after a constraint application is received by AEMO, allowing participants to make adjustments to bids as required.
  - DTS constraint – The market is notified that a transmission system constraint has been reached and that AEMO will be applying a constraint based on the transportation limits published in the most recent Victorian Gas Planning Report (VGPR).
- Scheduling SWN - Changes to system conditions, such as the end of day linepack target.
  - The market is usually notified three days before the gas day on which a change in linepack target will occur, unless a shorter notice change is required for operational reasons.
  - As discussed in section 2.1.2, if AEMO considers that SWP net withdrawals will occur over multiple gas days during winter, AEMO may decrease the linepack target by up to 20 TJ at the D+1 4:00 PM schedule.
- Scheduling SWN – Facility nomination confirmation
  - The market is notified when AEMO has a facility confirmation that varies from AEMO's scheduled quantity. AEMO contacts participants to determine whether their nominations are the same as the scheduled quantity to reduce the threat to system security.

AEMO will also communicate the following information via a Scheduling SWN when an abnormal market state exists:

- Longford pipeline pressure issue.
- Large increase of Effective Degree Day.[28]
- Low linepack reserve.
- Threat to system security.
- Ad hoc schedules.

Participants should review their INT134 Company Contact Detail report to ensure their contacts for Scheduling SWN and Gas Quality SWNs are up to date.

[28] Effective Degree Day (EDD) is a measure of coldness that includes temperature, sunshine hours, chill and seasonality. The higher the number, the more energy will be used for area heating purposes.

5.3 Natural Gas Bulletin Board

AEMO publishes data to the Natural Gas Services Bulletin Board[29] at each scheduling interval including:

- Scheduled flows for each scheduling interval
- Linepack capacity adequacy for each pipeline (status is indicated by green, amber or red flags).
- Capacity information for production facilities and pipelines.

Participants may find it useful to monitor this information as AEMO will change the linepack flag in the event of low linepack or a threat to system security.

5.4 Email reports

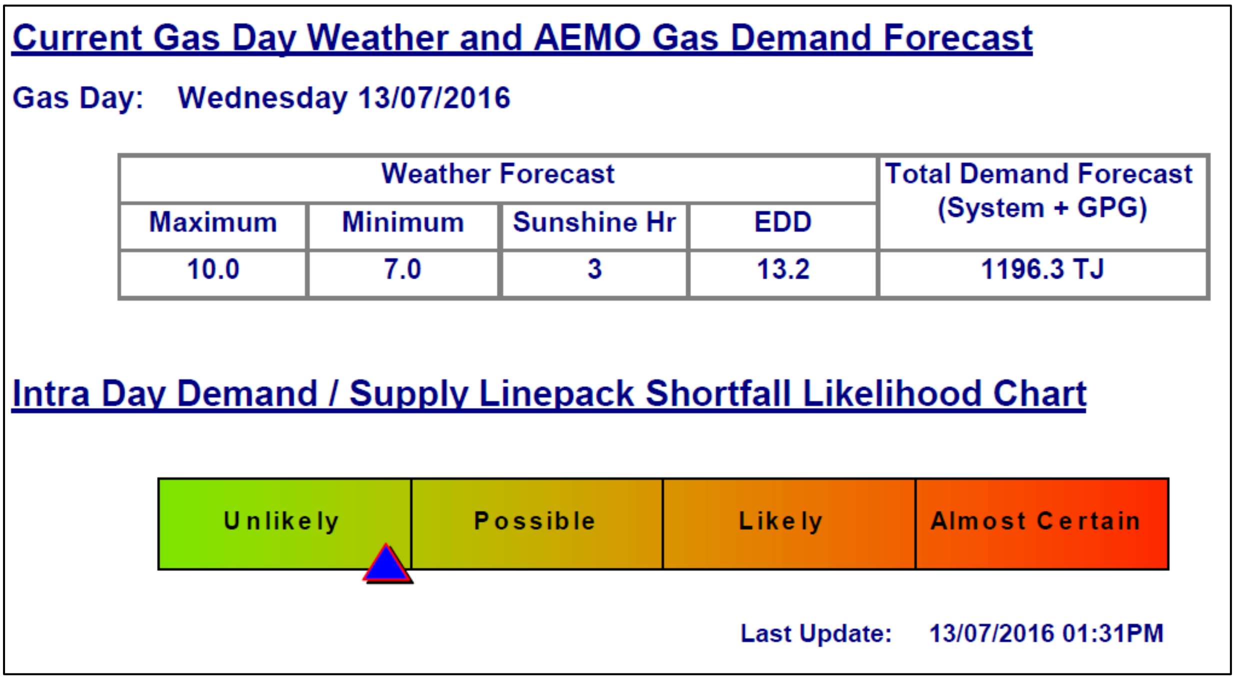
AEMO provides Registered Participants with a variety of reports via email. A Registered Participant can request to be added to the 'SupplyDemand' email distribution list by contacting AEMO's Support Hub.

5.4.1 Peak Day

On peak demand days, additional communications are sent to the market. One important notification is the intraday supply and demand shortfall likelihood chart, as shown in Figure 16.

Communication is triggered when the total demand forecast exceeds 1,150 TJ/d. AEMO will send an email notification at the 06:00, 10:00, 14:00 and 18:00 scheduling intervals. This communication indicates the likelihood of an intraday demand/supply linepack shortfall at each scheduling interval.

Figure 16 Weather and AEMO gas demand forecast



Current Gas Day Weather and AEMO Gas Demand Forecast

Gas Day: Wednesday 13/07/2016

Weather Forecast				Total Demand Forecast (System + GPG)
Maximum	Minimum	Sunshine Hr	EDD	
10.0	7.0	3	13.2	1196.3 TJ

Intra Day Demand / Supply Linepack Shortfall Likelihood Chart

Last Update: 13/07/2016 01:31PM

5.4.2 Daily reports

Everyday AEMO emails the participants that have subscribed to the 'SupplyDemand' distribution list the:

[29] For more information on the Natural Gas Services Bulletin Board (http://www.gasbb.com.au/) can be found in the Natural Gas Bulletin Board Procedures. Available here: http://www.gasbb.com.au/Bulletin%20Board%20Information/Procedures%20and%20Guides.aspx

- AEMO Gas Demand Forecast Report – is emailed after 4pm with a summary of system constraints and provides an overview of the gas flows expected in the Current Day, D+1 schedule and D+2 schedule and an indication of current gas day linepack condition.
- Operational Data Report – is emailed before 8am and summarises the previous gas day's schedule outcomes, actual flows as recorded by the AEMO Gas SCADA, and the price and flow information for the first schedule of the current gas day.

CHAPTER 6. EMERGENCY MANAGEMENT

AEMO manages threats to system security and gas emergencies using a consultative and risk-based approach, to ensure:

- Relevant information and knowledge is shared during an event.
- Decisions are clear and informed.

AEMO's Emergency Management Framework (EMF) and Incident Management Plan (IMP) align AEMO's preparedness and response capabilities, and are supported by other relevant plans and protocols across both the electricity and gas markets, minimising risk:

- The EMF outlines the incident management arrangements and responsibilities for incident coordination and managing the Incident Coordination Team (ICT). All AEMO emergency and incident management documentation, including business continuity plans, align with the framework.
- The IMP is an operational document that outlines how the Incident Coordinator and ICT will be notified and activated to deal with incidents. It also informs how AEMO returns to normal operations as soon as possible. The IMP complements other industry and government emergency policies and procedures.
- The ICT can be activated in isolation in accordance with the triggers outlined in the IMP and/or in support of multiple events impacting other emergency plans across the electricity and gas markets.

Once activated, the incident coordination team takes responsibility for:

- All activities undertaken to manage the incident.
- Establishing AEMO's incident coordination centre.
- Managing the interface with organisations and people operating outside the incident management structure, as well as with communities and people likely to be affected by the incident.

6.1 Legislation and rules

The *National Gas (Victoria) Act 2008* is the legislation for the application of the National Gas Law (NGL) and rules in Victoria.

The NGL defines an emergency applied in Victoria. It specifies what is required to prepare for gas emergencies, the requirements for the Gas Emergency Protocol, and that registered participants must comply with the Gas Emergency Protocol.

6.2 Emergencies

Emergencies are defined under the Section 333 of the National Gas Rules (NGR) as follows:

> *(1) An emergency occurs when:*
>
> *(a) AEMO reasonably believes there to be a situation which may threaten:*
>
> *(i) reliability of gas supply; or*
>
> *(ii) system security or the security of a declared distribution system; or*
>
> *(iii) public safety,*
>
> *and AEMO in its absolute discretion considers that the situation is an emergency and declares there to be an emergency; or*
>
> *(b) AEMO declares there to be an emergency at the direction of a government authority authorised to give such directions.*

AEMO will declare an emergency if it reasonably believes that an operational response cannot address the issue. It will implement the declaration by issuing an Emergency Declaration Notice to the Emergency Manager, Duty Manager, or General Manager of each registered participant.

AEMO is also responsible for maintaining the Gas Emergency Protocol. This protocol consists of:[30]

- *Gas Load Curtailment and Gas Rationing and Recovery Guidelines*.
- *Wholesale Market System Security Procedures*.
- *Emergency Procedures (Gas)*.

The *Gas Load Curtailment and Gas Rationing and Recovery Guidelines* define classes of gas customers within prioritised curtailment tables, from which curtailment lists are derived. These guidelines are based on system security criteria and can be modified by government direction.

The *Wholesale Market System Security Procedures (Victoria)* set the thresholds for operation of the DTS, so threats to system security are averted or minimised.

The *Emergency Procedures (Gas)* guide the management, preparation, response and recovery for gas emergencies in Victoria. The procedures are underpinned by the principles of maintaining the gas reliability, maintaining DTS system security, and minimising risk to public safety.

The NGR outlines four key requirements for registered participants. Each must:

- Notify AEMO as soon as practicable of any emergency or situation that may threaten system security.
- Use best endeavours to ensure that its safety plan (if any) permits it to comply with emergency directions.
- Provide AEMO with emergency contacts (including an email address, telephone and fax number, name and title) of an appropriate representative who has the authority and responsibility to act in the event of an emergency.
- Ensure all relevant officers, staff, and customers are familiar with the emergency protocol and the registered participant's safety plan or procedures.

AEMO's powers during an emergency

AEMO may use section 91BC of the NGL to issue directions for managing:

- The operation or use of any equipment or installation.
- The control of natural gas flow.

[30] Gas Emergency Protocol documents can be found at: http://www.aemo.com.au/Gas/Emergency-management/Victorian-role

- Any other matter that may affect the safety, security or reliability of the declared transmission or declared distribution systems.

While AEMO's powers under NGL 91BC can be used without declaring an emergency or threat to system security, it is unlikely AEMO would invoke these powers without declaring one or both.

Energy Safe Victoria power to issue directions

During a gas emergency, the Director of Energy Safe Victoria (ESV) may also issue a direction that ESV believes is needed to make the situation safe. The intent is to regulate the available gas supply (having regard to community needs), and facilitate the reliability of gas supply or the security of systems for transmitting or distributing gas.

The Governor and the Minister for Energy

The Governor may also declare a proclamation under Part 9 of the *Gas Industry Act*, if it appears that the available supply of gas is (or is likely to become) insufficient for the community's essential needs. The proclamation remains in effect until the Governor revokes it. While the proclamation is in force, the Minister for Energy may give any direction necessary to ensure the safe and secure supply of gas.

6.3 Threats to System Security

A threat to system security[31] can be indicated by any one of the following:

- The annual planning reviews prepared by AEMO.
- An operating schedule.
- Any other fact or circumstance which AEMO becomes aware of.

A threat to system security may impact the DTS partially or as a whole. AEMO has the power to indicate a threat to system security if it reasonably believes some level of operational response can address the issue, otherwise an "emergency" will be declared.

Market response and Intervention

AEMO may take the following measures to overcome a threat to system security (under s.91BC of the NGL):

- Directing the injection of LNG.
- Curtailment[32] (in accordance with curtailment tables).
- Increasing withdrawals.
- Using reasonable endeavours to inject gas which is available, including non-firm gas.
- Injecting off-specification gas.
- Doing anything AEMO believes necessary in the circumstances.

6.4 Emergency Communications

Registered Participants must have registered with AEMO at least one emergency contact. That is a person having appropriate authority and responsibility within their organisation to act as the primary contact for AEMO in the event of an emergency.

Registered participants must provide AEMO with a telephone number and facsimile number at which a representative(s) is contactable by AEMO, 24 hours a day, seven days a week. This person will be

[31] A threat to system security is defined with rule 341 of the NGR.
[32] In the event of a threat to system security attributable to a transmission constraint AEMO will curtail customers in accordance with sections 3 and 4 of the Gas Load Curtailment and Gas Rationing and Recovery Guidelines.

contacted for in the event of an emergency under the *Emergency Procedures Gas* and the *Victorian Energy Emergency Communications Protocol*.

MEASURES AND ABBREVIATIONS

Units of measure

Abbreviation	Unit of measure
$	Australian dollars
EDD	Effective degree days
kPa	Kilopascals
PJ	Petajoule (1 PJ = 1,000 TJ)
TJ	Terajoule (1 TJ = 1,000 GJ)
TJ/d	Terajoules per day
TJ/hr	Terajoules per hour

Abbreviations

Abbreviation	Expanded name
AEMO	Australian Energy Market Operator
DCG	Dandenong City Gate
DFPC	Directional Flow Point Constraint
DTS	Declared Transmission System
EDD	Effective Degree Day
EGP	Eastern Gas Pipeline
EMF	Emergency Management Framework
ESV	Energy Safe Victoria
GBB	Natural Gas Services Bulletin Board
GPG	Gas-powered generation
ICT	Incident Coordination Team
IMP	Incident Management Plan
MIBB	Market Information Bulletin Board
LMP	Longford to Melbourne Pipeline
LNG	Liquefied natural gas
NEM	National Electricity Market
NGL	National Gas Law
NGR	National Gas Rules
NFTC	Net Flow Transportation Constraint
OS	Operating Schedule
PS	Pricing Schedule
SDPC	Supply and Demand Point Constraint
SSC	Supply Source Constraint
STTM	Short Term Trading Market
SWN	System-wide notice
SWP	South West Pipeline
TGP	Tasmanian Gas Pipeline
UGS	Underground Gas Storage
VNI	Victorian Northern Interconnect

Abbreviation	Expanded name
WTS	Western Transmission System

GLOSSARY

Term	Definition
1-in-2 system demand day	The 1-in-2 system demand day demand projection has a 50% probability of exceedance (POE). This projected level of demand is expected, on average, to be exceeded once in two years. Also known as the 50% peak day.
1-in-20 system demand day	The 1-in-20 system demand day demand projection (for severe weather conditions) has a 5% probability of exceedance (POE). This is expected, on average, to be exceeded once in 20 years. Also known as the 95% peak day.
augmentation	The process of upgrading the capacity or service potential of a transmission (or a distribution) pipeline.
Authorised Maximum Daily Quantity	Authorised Maximum Daily Quantity (Authorised MDQ) and Authorised MDQ Credit Certificate are transportation rights in the DTS, collectively known as AMDQ. Authorised MDQ is a withdrawal right for customers and/or market participants on the DTS for transported gas injected at Longford. Subsequent capacity increases to the DTS such as South West Pipeline, the Western Transmission System and the Bass Gas project have been allocated as AMDQ Credit Certificates. AMDQ is an input to: • Determining congestion uplift charges payable by a market participant for each scheduling interval of a gas day as part of the funding of ancillary payments. • Tie-breaking rights when scheduling equal priced injections or withdrawals bids, and in determining the order of curtailment in the event of an emergency.
BassGas	A project that sources gas from the Bass Basin for supply to the gas Declared Transmission System (gas DTS), and injected at Pakenham.
Capacity	Pipeline transportation capacity.
Culcairn	The gas transmission system interconnection point between Victoria and New South Wales.
constraint	Any limitation causing some defined gas property (such as minimum pressure) to fall outside its acceptable range.
Declared Transmission System	The declared gas transmission system in Victoria, in accordance with the National Gas Law. Owned by APA VTS and operated by AEMO, the DTS serves Gippsland, Melbourne, Central and Northern Victoria, Albury, the Murray Valley region, and Geelong, and extends to Port Campbell.
distribution	The transport of gas over a combination of high pressure and low pressure pipelines from a city gate to customer delivery points.
distribution system	Pipelines for the conveyance of gas with one or other of the following characteristics: • A maximum allowable operating pressure of 515 kPa or less. • Uniquely identified as a distribution pipeline in a distributor's access arrangement, where the maximum operating pressure is greater than 515 kPa.
distributor	The service provider of the distribution pipelines that transport gas from transmission pipelines to customers.
Eastern Gas Pipeline	The east coast pipeline from Longford to Sydney.
Effective Degree Day	A measure of coldness that includes temperature, sunshine hours, chill and seasonality. The higher the number, the more energy will be used for area heating purposes. The Effective Degree Day (EDD) is used to model the daily gas demand-weather relationship.
Facility operator	Producers, Storage Providers, and interconnected transmission pipeline service providers in the DTS.
firm capacity	Guaranteed or contracted capacity to supply gas.
gas	See natural gas.
gas market (market)	A market administered by AEMO for the injection of gas into, and the withdrawal of gas from, the gas transmission system and the balancing of gas flows in or through the gas transmission system.
gas-powered generation (GPG)	Where electricity is generated from gas turbines (combined-cycle gas turbine (CCGT) or open-cycle gas turbine (OCGT)).
Gas Statement of Opportunities (GSOO)	The GSOO is published annually by AEMO, under the National Gas Law and Part 15D of the National Gas Rules, to report on the projected adequacy of eastern and south-eastern Australian gas markets to supply forecast maximum demand and annual consumption.

Term	Definition
Gigajoule (GJ)	An International System of Units (SI) unit, 1 gigajoule equals 1,000 J.
injection	The physical injection of gas into the transmission system.
Interconnect (The)	Refers to the pipeline from Barnawartha to Wagga Wagga connecting the Victoria and New South Wales transmission systems at Culcairn. This does not include the VicHub (Longford) and SEA Gas (Iona) interconnections.
Lateral pipeline	A pipeline branch off a larger pipeline.
linepack	The pressurised volume of gas stored in the pipeline system. Linepack is essential for gas transportation through the pipeline system throughout each day, and is required as a buffer for within-day balancing.
liquefied natural gas (LNG)	Natural gas that has been converted to liquid for ease of storage or transport. The Melbourne liquefied natural gas (LNG) storage facility is located at Dandenong.
maintenance	Work carried out by service providers, Producers and Storage Providers that, in AEMO's opinion, may affect any of: • AEMO's ability to supply gas through the declared transmission system. • AEMO's ability to operate the declared transmission system. • DTS capacity. • System security. • The efficient operation of the DTS generally. It includes work carried out on pipeline equipment, but does not include maintenance required to avert or reduce the impact of an emergency.
market participant	A party who is eligible to participate in an energy market operated by AEMO in one or more of the following roles: • A market generator, market customer, or a market network service provider (electricity). • Storage provider. • Transmission customer. • Distribution customer. • Retailer. • Trader (gas).
maximum allowable operating pressure (MAOP)	The maximum pressure at which a pipeline is licensed to operate.
maximum daily quantity	Maximum daily quantity (MDQ) of gas supply or demand. See also Authorised Maximum Daily Quantity.
National Gas Forecasting Report (NGFR)	The NGFR is published annually by AEMO, under clause 91D of the National Gas Law, to report on forecast maximum demand and annual consumption in eastern and south-eastern Australia.
Natural gas	A naturally occurring hydrocarbon comprising methane (CH_4) (between 95% and 99%) and ethane (C_2H_6).
Natural Gas Services Bulletin Board (GBB)	The GBB (http://www.gasbb.com.au/) is an online gas market and system information website covering all major gas production fields, major demand centres and natural gas transmission pipeline systems of South Australia, Victoria, Tasmania, NSW, the ACT, and Queensland. It was established in 2008 and is operated by AEMO.
Operational response LNG	Meeting a demand peak using injections of vaporised liquefied natural gas (LNG).
peak shaving	See operational response LNG
Petajoule (PJ)	An International System of Units (SI) unit, 1 petajoule equals 1,000 TJ (or 10^{15} joules). Also PJ/yr. or petajoules per year.
pipeline	A pipe or system of pipes for or incidental to the conveyance of gas and includes a part of such a pipe or system.
planned outage	A controlled outage of a transmission element for maintenance and/or construction purposes, or due to anticipated failure of primary or secondary equipment for which there is greater than 24 hours' notice.
probability of exceedance	Refers to the probability that a forecast peak demand figure will be exceeded. For example, a forecast 1-in-20 peak demand will, on average, be exceeded only 1 year in every 20.
scheduling	The process of scheduling bids that AEMO is required to carry out in accordance with Part 19 of the National Gas Rules for the purpose of balancing gas flows in the transmission system and maintaining transmission system security.

Term	Definition
SEA Gas Pipeline	The 680 km pipeline from Iona to Adelaide, principally constructed to ship gas to South Australia.
South West Pipeline	The 500 mm pipeline from Lara (Geelong) to Port Campbell.
storage facility	A facility for storing gas, including the liquefied natural gas (LNG) storage facility and the Iona Underground Gas Storage (UGS).
system capacity	The maximum demand that can be met on a sustained basis over several days given a defined set of operating conditions. System capacity is a function of many factors and accordingly a set of conditions and assumptions must be understood in any system capacity assessment. These factors include the following: • Load distribution across the system. • Hourly load profiles throughout the day at each delivery point. • Heating values and the specific gravity of injected gas at each injection point. • Initial linepack and final linepack and its distribution throughout the system. • Ground and ambient air temperatures. • Minimum and maximum operating pressure limits at critical points throughout the system. • Compressor station power and efficiency.
system constraint	See Declared Transmission System constraint.
system demand	Demand from Tariff V (residential, small commercial and industrial customers nominally consuming less than 10 TJ of gas per annum) and Tariff D (large commercial and industrial customers nominally consuming more than 10 TJ of gas per annum). It excludes gas-powered generation (GPG) demand, exports, and gas withdrawn at Iona UGS.
system injection point	A gas transmission system connection point designed to permit gas to flow through a single pipe into the transmission system, which may also be, in the case of a transfer point, a system withdrawal point.
system withdrawal point	A gas Declared Transmission System (gas DTS) connection point designed to permit gas to flow through a single pipe out of the transmission system, which may also be, in the case of a transfer point, a system injection point.
Tariff D	The gas transportation tariff applying to daily metered sites with annual consumption greater than 10,000 GJ or maximum hourly quantity (MHQ) greater than 10 GJ and that are assigned as Tariff D in the AEMO meter installation register. Each site has a unique Metering Identity Registration Number (MIRN).
Tasmanian gas pipeline	The pipeline from VicHub (Longford) to Tasmania.
Terajoule (TJ)	An International System of Units (SI) unit, 1 terajoule equals 1,000 GJ (or 10^{12} joules). Also TJ/d or terajoule per day.
transmission pipeline	A pipeline for the conveyance of gas that is licensed under the Pipelines Act and has a maximum design pressure exceeding 1,050 kPa.
transmission system	The transmission pipelines or system of transmission pipelines forming part of the 'gas transmission system' as defined under the Gas Industry Act.
Underground Gas Storage (UGS)	The Iona Underground Gas Storage (UGS) facility at Port Campbell which supplies gas to Victoria to meet winter peak demand, and in summer supports South Australian GPG demand via the SEA Gas Pipeline and, as needed, Victorian demand if capacity is reduced at other facilities.
VicHub	The interconnection between the Eastern Gas Pipeline (EGP) and the gas Declared Transmission System (DTS) at Longford, facilitating gas trading at the Longford hub.
Western Transmission System (WTS)	The transmission pipelines serving the area from Port Campbell to Portland.
Winter	1 May to 30 September as per the *Wholesale Market System Security Procedure*